

ATTACHMENT K -- APPENDIX

Preface. The provisions of the Appendix incorporate into the Tariff for ease of reference the provisions of Schedule 1 of the Operating Agreement. As a result, this Appendix will be modified, subject to the approval of the Federal Energy Regulatory Commission, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 1 of the Operating Agreement. All references in this Appendix to “Agreement” or “Schedules” are references to the Operating Agreement and the schedules thereto unless otherwise noted. References to Schedule 1 are references to this Appendix.

1. MARKET OPERATIONS

1.1 Introduction.

This Schedule sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the PJM Interchange Energy Market within the PJM Region. This Schedule addresses each of the three time-frames pertinent to the daily operation of the PJM Interchange Energy Market: Prescheduling, Scheduling, and Dispatch.

1.2 Cost-based Offers.

Unless and until the FERC shall authorize the use of market-based prices in the PJM Interchange Energy Market, all offers for energy or other services to be sold on the PJM Interchange Energy Market from generating resources located within the PJM Region shall not exceed the variable cost of producing such energy or other service, as determined in accordance with Schedule 2 to this Agreement and applicable regulatory standards, requirements and determinations; provided that, a Market Seller may offer to the PJM Interchange Energy Market the right to call on energy from a resource the output of which has been sold on a bilateral basis, with the rate for such energy if called equal to the curtailment rate specified in the bilateral contract.

1.2A Transmission Losses.

1.2A.1 Description of Transmission Losses.

Transmission losses refer to the loss of energy in the transmission of electricity from generation resources to load, which is dissipated as heat through transformers, transmission lines and other transmission facilities.

1.2A.2 Inclusion of State Estimator Transmission Losses.

Whenever in this Schedule 1, transmission losses are included in the determination of a charge, credit, load (including deviations), or demand reduction, it is explicitly so stated and such included losses shall be those losses incurred on facilities

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

included in the PJM network model and determined by, and reflected in, the PJM State Estimator. Absent such explicit statement, such losses are not included in the determination.

1.2A.3 Other Losses.

Losses incurred on facilities not included in the PJM network model and therefore not reflected in the PJM State Estimator may be included in the determination of charges, credits, load (including real-time deviations) or demand reductions, as determined by electric distribution companies, unless this Schedule explicitly excludes such losses.

1.3 Definitions.

1.3.1 Acceleration Request.

“Acceleration Request” shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

“Auction Revenue Rights” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B 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 Section 7.4.3 of this Schedule.

1.3.1B.01 Congestion Price.

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

1.3.1A.001 Batch Load Demand Resource.

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

1.3.1A.01 Curtailment Service Provider.

“Curtailed Service Provider” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.

1.3.1B.02 Day-ahead Congestion Price.

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

1.3.1C Day-ahead Energy Market.

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

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

1.3.1D Day-ahead Prices.

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

1.3.1D.01 Day-ahead Scheduling Reserves.

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

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

“Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with Reliability First Corporation and SERC reliability standards, or those of any additional and/or successor regional reliability organization(s) that are responsible for establishing reliability requirements for the PJM Region, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

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

1.3.1D.04 Day-ahead Scheduling Reserves Market.

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1E Decrement Bid.

“Decrement Bid” shall mean a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

1.3.1D.01 Demand Resource.

“Demand Resource” shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

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

1.3.2 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.

1.3.2A Economic Load Response Participant.

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market through reductions in demand.

1.3.3 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.

1.3.4 External Resource.

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

1.3.5 Financial Transmission Right.

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: March 31, 2008

Effective: May 30, 2008

1.3.5A Financial Transmission Right Obligation.

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

“Generating Market Buyer” shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer’s load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

“Generator Forced Outage” shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

“Generator Maintenance Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

“Generator Planned Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9A Increment Bid.

“Increment Bid” shall mean an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified location in the Day-ahead Energy Market.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

1.3.10 Internal Market Buyer.

“Internal Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11A 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.

1.3.11B 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 Section 2 of Schedule 1 of this Agreement.

1.3.12 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.

1.3.12A 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.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

1.3.13 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 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 Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.14 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.

1.3.14A 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.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

1.3.15 Network Resource.

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

1.3.16 Network Service User.

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

1.3.17 Network Transmission Service.

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

1.3.18 Normal Maximum Generation.

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

1.3.19 Normal Minimum Generation.

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

1.3.20 Offer Data.

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

1.3.21 Office of the Interconnection Control Center.

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: July 19, 2006

Effective: September 18, 2006

1.3.21A On-Site Generators.

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

1.3.22 Operating Day.

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

1.3.23 Operating Margin.

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

1.3.24 Operating Margin Customer.

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

1.3.25 PJM Interchange.

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

1.3.26 PJM Interchange Export.

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

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

1.3.27 PJM Interchange Import.

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

1.3.28 PJM Open Access Same-time Information System.

“PJM Open Access Same-time Information System” shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

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

1.3.28B Planning Period Balance.

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

1.3.29 Point-to-Point Transmission Service.

“Point-to-Point Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.30 Ramping Capability.

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

1.3.30.01 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.

1.3.30.02 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.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

1.3.30A 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.

1.3.30B 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.

1.3.30B.01 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.

1.3.31 Regulation.

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

1.3.31.01 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 or a change in any other relevant factor that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2 (h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 19, 2007

Effective: August 21, 2007

1.3.31.02 Special Member.

“Special Member” shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response Program.

1.3.31A [RESERVED]

1.3.31B [RESERVED]

1.3.32 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.

1.3.33 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 Section 2 of this Schedule.

1.3.33A State Estimator.

“State Estimator” shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B 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 used to power synchronous condensers, used for pumping at a pumped storage facility, or used in association with restoration or black start service.

1.3.33B.01 Synchronized Reserve.

“Synchronized Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Demand 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.

1.3.33B.02 Synchronized Reserve Event.

“Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-schedule Synchronized Reserve capability.

1.3.33B.03 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 Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

1.3.34 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 in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

“Transmission Customer” shall mean an entity using Point-to-Point Transmission Service.

1.3.37 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.

1.3.37A 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.

1.3.37B Transmission Loading Relief Customer.

“Transmission Loading Relief Customer” shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C 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 Section 5 of this Schedule.

1.3.38 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 this Agreement or the PJM Manuals.

1.3.39 Zonal Base Load.

“Zonal Base Load” shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: July 3, 2006

Effective: March 1, 2007

1.4 Market Buyers.

1.4.1 Qualification.

- (a) To become a Market Buyer, an entity shall submit an application to the Office of the Interconnection, in such form as shall be established by the Office of the Interconnection.
- (b) An applicant that is a Load Serving Entity or that will purchase on behalf of or for ultimate delivery to a Load Serving Entity shall establish to the satisfaction of the Office of the Interconnection that the end-users that will be served through energy and related services purchased in the PJM Interchange Energy Market, are located electrically within the PJM Region, or will be brought within the PJM Region prior to any purchases from the PJM Interchange Energy Market. Such applicant shall further demonstrate that:
 - i) The Load Serving Entity for the end users is obligated to meet the requirements of the Reliability Assurance Agreement, Reliability Assurance Agreement-South or Reliability Assurance Agreement-West, as applicable; and
 - ii) The Load Serving Entity for the end users has arrangements in place for Network Transmission Service or Point-To-Point Transmission Service for all PJM Interchange Energy Market purchases.
- (c) An applicant that is not a Load Serving Entity or purchasing on behalf of or for ultimate delivery to a Load Serving Entity shall demonstrate that:
 - i) The applicant has obtained or will obtain Network Transmission Service or Point-To-Point Transmission Service for all PJM Interchange Energy Market purchases; and
 - ii) The applicant's PJM Interchange Energy Market purchases will ultimately be delivered to a load in another Control Area that is recognized by NERC and that complies with NERC's standards for operating and planning reliable bulk electric systems.
- (d) An applicant shall not be required to obtain transmission service for purchases from the PJM Interchange Energy Market to cover quantity deviations from its sales in the Day-ahead Energy Market.
- (e) All applicants shall demonstrate that:
 - i) The applicant is capable of complying with all applicable metering, data storage and transmission, and other reliability, operation, planning and accounting standards and requirements for the operation of the PJM Region and the PJM Interchange Energy Market;

- ii) The applicant meets the creditworthiness standards established by the Office of the Interconnection, or has provided a letter of credit or other form of security acceptable to the Office of the Interconnection; and
 - iii) The applicant has paid all applicable fees and reimbursed the Office of the Interconnection for all unusual or extraordinary costs of processing and evaluating its application to become a Market Buyer, and has agreed in its application to subject any disputes arising from its application to the PJM Dispute Resolution Procedures.
- (f) The applicant shall become a Market Buyer upon a final favorable determination on its application by the Office of the Interconnection as specified below, and execution by the applicant of counterparts of this Agreement.

1.4.2 Submission of Information.

The applicant shall furnish all information reasonably requested by the Office of the Interconnection in order to determine the applicant's qualification to be a Market Buyer. The Office of the Interconnection may waive the submission of information relating to any of the foregoing criteria, to the extent the information in the Office of the Interconnection's possession is sufficient to evaluate the application against such criteria.

1.4.3 Fees and Costs.

The Office of the Interconnection shall require all applicants to become a Market Buyer to pay a uniform application fee, initially in the amount of \$1,500, to defray the ordinary costs of processing such applications. The application fee shall be revised from time to time as the Office of the Interconnection shall determine to be necessary to recover its ordinary costs of processing applications. Any unusual or extraordinary costs incurred by the Office of the Interconnection in processing an application shall be reimbursed by the applicant.

1.4.4 Office of the Interconnection Determination.

Upon submission of the information specified above, and such other information as shall reasonably be requested by the Office of the Interconnection, the Office of the Interconnection shall undertake an evaluation and investigation to determine whether the applicant meets the criteria specified above. As soon as practicable, but in any event not later than 60 days after submission of the foregoing information, or such later date as may be necessary to satisfy the requirements of the Reliability Assurance Agreement, Reliability Assurance Agreement-South or Reliability Assurance Agreement-West, the Office of the Interconnection shall notify the applicant and the members of the Members Committee of its determination, along with a written summary of the basis for the

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: May 11, 2004

Effective: May 1, 2005

determination. The Office of the Interconnection shall respond promptly to any reasonable and timely request by a Member for additional information regarding the basis for the Office of the Interconnection's determination, and shall take such action as it shall deem appropriate in response to any request for reconsideration or other action submitted to the Office of the Interconnection not later than 30 days from the initial notification to the Members Committee.

1.4.5 Existing Participants.

Any entity that was qualified to participate as a Market Buyer in the PJM Interchange Energy Market under the Operating Agreement of PJM Interconnection L.L.C. in effect immediately prior to the Effective Date shall continue to be qualified to participate as a Market Buyer in the PJM Interchange Energy Market under this Agreement.

1.4.6 Withdrawal.

(a) An Internal Market Buyer that is a Load Serving Entity may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal not earlier than the effective date of (i) its withdrawal from the Reliability Assurance Agreement, Reliability Assurance Agreement-South or Reliability Assurance Agreement-West, or (ii) the assumption of its obligations under the Reliability Assurance Agreement, Reliability Assurance Agreement-South or Reliability Assurance Agreement-West by an agent that is a Market Buyer.

(b) An External Market Buyer or an Internal Market Buyer that is not a Load Serving Entity may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice.

(c) Withdrawal from this Agreement shall not relieve a Market Buyer of any obligation to pay for electric energy or related services purchased from the PJM Interchange Energy Market prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions or events occurring prior to such withdrawal; and provided, further, that withdrawal from this Agreement shall not relieve any Market Buyer of any obligations it may have under, or constitute withdrawal from, any other Related PJM Agreement.

(d) A Market Buyer that has withdrawn from this Agreement may reapply to become a Market Buyer in accordance with the provisions of this Section 1.4, provided it is not in default of any obligation incurred under this Agreement.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: May 11, 2004

Effective: May 1, 2005

1.5 Market Sellers.

1.5.1 Qualification.

A Member that demonstrates to the Office of the Interconnection that the Member meets the standards for the issuance of an order mandating the provision of transmission service under section 211 of the Federal Power Act, as amended by the Energy Policy Act of 1992, may become a Market Seller upon execution of this Agreement and submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule. All Members that are Market Buyers shall become Market Sellers upon submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule.

1.5.2 Withdrawal.

(a) A Market Seller may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice; provided, however, that withdrawal shall not relieve a Market Seller of any obligation to deliver electric energy or related services to the PJM Interchange Energy Market pursuant to an offer made prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions, or events occurring prior to such withdrawal; and provided, further, that withdrawal shall not relieve any entity that is a Market Seller and is also a Market Buyer of any obligations it may have as a Market Buyer under, or constitute withdrawal as a Market Buyer from, this Agreement or any other Related PJM Agreement.

(b) A Market Seller that has withdrawn from this Agreement may reapply to become a Market Seller at any time, provided it is not in default with respect to any obligation incurred under this Agreement.

1.5A Economic Load Response Participant.

1.5A.1 Qualification.

A Member or Special Member that is an end use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of section 1.5A. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of Section 1.5A.10.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by the Office of the Interconnection for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in section 1.4.3 of this Agreement; (ii) liability under section 15.2 of this Agreement for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

Prior to participating in the PJM Interchange Energy Market, Economic Load Response Participants must complete the Economic Load Response Registration Form posted on the Office of the Interconnection's website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the appropriate electric distribution company or Load Serving Entity of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation and for confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. In the absence of a response, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations. In the event that the load is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end user or appropriate Curtailment Service Provider or Load Serving Entity that the Economic Load Response Participant has met the requirements of this section 1.5A. End-use customers that desire not to be simultaneously registered to reduce demand under the Emergency Load Response Program and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

1.5A.4 Metering.

Economic Load Response Participants must have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis that either meets the electric distribution company requirements for accuracy or has a maximum error of two percent over the full range of the meter (including potential transformers and current transformers) and that meets the requirements set forth in the PJM Manuals. The Economic Load Response participant must meter reductions in demand either by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, data reflecting meter readings for each hour during in which the load reduction occurred must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Active Load Management Participation.

An Active Load Management (“ALM”) customer may qualify to submit offers to reduce demand in the PJM Interchange Energy Market during Active Load Management events provided that, if the ALM customer entered into an ALM contract prior to June 1, 2002, such contract explicitly excludes payment or credit for energy not consumed during ALM events. In the event that the Load Serving Entity that is eligible to receive an ALM credit based on a contract with an ALM customer entered into prior to June 1, 2002 indicates that such contract does not permit the ALM customer to simultaneously participate in the PJM Interchange Energy Market pursuant to this section 1.5A.6, then such ALM customer may qualify to submit offers to reduce demand in the PJM Interchange Energy Market only for amounts in excess of its contractual obligations under its ALM contract. An ALM customer that has entered into an ALM

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: Upon Implementation Date

Issued On: March 27, 2006

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER06-406-000, issued February 24, 2006, 114 FERC ¶ 61,201 (2006).

contract on or after June 1, 2002 shall be eligible to submit offers to reduce demand in the Interchange Energy Market without limitation notwithstanding any terms or conditions to the contrary in its ALM contract.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The customer or its Curtailment Service Provider or Load Serving Entity must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection ("Pilot Period"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period. Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.4 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Demand Resource Provision of Synchronized Reserve or Day-Ahead Scheduling Reserves.

(a) A Batch Load Demand Resource may provide Synchronized Reserve or Day-Ahead Scheduling Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Demand Resource" pursuant to section 1.3.1A.001 of this Schedule. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.

(b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-Ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection

requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection's filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-Ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-Ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-Ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Day-Ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Day-Ahead Scheduling Reserves to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants may participate in the Day-ahead and Real-time Energy Markets as dispatchable or self-scheduled resources, provided that Demand Resources that are self-scheduled pursuant to Section 1.5A.9(a) shall not be dispatched by the Office of the Interconnection pursuant to this section.

(a) Self-scheduled Demand Resources shall be subject to the following requirements:

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 30, 2008

Effective: July 7, 2008

- i. An Economic Load Response Participant self-scheduling a Demand Resource shall notify the Office of the Interconnection no less than 5 minutes prior to beginning a load reduction event and no more than 7 days prior to an event;
- ii. Economic Load Response Participants may self-schedule a Demand Resource intra-hour;
- iii. A Notification pursuant to this section may be withdrawn or adjusted downward during the relevant event hour, but not after the event hour;

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 30, 2008

Effective: July 7, 2008

- iv. A Notification submitted pursuant to this section shall include the start and stop times of the event and the amount of the demand reduction;
- v. The event period for self-scheduled Demand Resources shall be defined as all hours in the day for which the Economic Load Response Participant has provided a Notification.

1.5A.10 Economic Load Response Participant Aggregation.

Aggregations pursuant to Section 1.5A.1 shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity;
- iii. All end-use customers in an aggregation that settle at zonal or nodal prices shall be located in the same Zone or at the same node, respectively;
- iv. If all end-use customers in an aggregation are not subject to the same generation and transmission charges, the generation and transmission charge for the aggregation shall be the load weighted average of the generation and transmission charges for all end-use customers in the aggregation. The Economic Load Response Participant shall provide the load weighted average, the calculation of the load weighted average, and the supporting data to the LSE and PJM. For the purposes of this section, the applicable generation and transmission charges are the charges an end-use customer would have otherwise paid the Load Serving Entity absent the demand reduction;
- v. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.4 and 3.3A.5.

1.6 Office of the Interconnection.

1.6.1 Operation of the PJM Interchange Energy Market.

The Office of the Interconnection shall operate the PJM Interchange Energy Market in accordance with this Agreement.

1.6.2 Scope of Services.

The Office of the Interconnection shall, on behalf of the Market Participants, perform the services pertaining to the PJM Interchange Energy Market specified in this Agreement, including but not limited to the following:

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 30, 2008

Effective: July 7, 2008

- i) Administer the PJM Interchange Energy Market as part of the PJM Region, including scheduling and dispatching of generation resources, accounting for transactions, rendering bills to the Market Participants, receiving payments from and disbursing payments to the Market Participants, maintaining appropriate records, and monitoring the compliance of Market Participants with the provisions of this Agreement, all in accordance with applicable provisions of the Office of the Interconnection Agreement, and the Schedules to this Agreement;
- ii) Review and evaluate the qualification of entities to be Market Buyers, Market Sellers, or Economic Load Response Participants under applicable provisions of this Agreement;
- iii) Coordinate, in accordance with applicable provisions of this Agreement, the Reliability Assurance Agreement, the Reliability Assurance Agreement-South, the Reliability Assurance Agreement-West, and the Consolidated Transmission Owners Agreement, maintenance schedules for generation and transmission resources operated as part of the PJM Region;
- iv) Provide or coordinate the provision of ancillary services necessary for the operation of the PJM Region or the PJM Interchange Energy Market;
- v) Determine and declare that an Emergency is expected to exist, exists, or has ceased to exist, in all or any part of the PJM Region, or in another directly or indirectly interconnected Control Area and serve as a primary point of contact for interested state or federal agencies;
- vi) Enter into (a) agreements for the transfer of energy in conditions constituting an Emergency in the PJM Region or in an interconnected Control Area, and the mutual provision of other support in such Emergency conditions with other interconnected Control Areas, and (b) purchases of Emergency energy offered by Members from resources that are not Capacity Resources in conditions constituting an Emergency in the PJM Region;

- vii) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable Regional Reliability Council principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement;
- viii) Protect confidential information as specified in this Agreement; and
- ix) Send a representative to meetings of the Members Committee or other Committees, subcommittees, or working groups specified in this Agreement or formed by the Members Committee when requested to do so by the chair or other head of such committee or other group.

1.6.3 Records and Reports.

The Office of the Interconnection shall prepare and maintain such records and prepare such reports, including, but not limited to quarterly budget reports, as are required to document the performance of its obligations to the Market Participants hereunder in a form adopted by the Office of the Interconnection upon consideration of the advice and recommendations of the Members Committee. The Office of the Interconnection shall also produce special reports reasonably requested by the Members Committee and consistent with FERC's standards of conduct; provided, however, the Market Participants shall reimburse the Office of the Interconnection for the costs of producing any such report. Notwithstanding the foregoing, the Office of the Interconnection shall not be required to disclose confidential or commercially sensitive information in any such report.

1.6.4 PJM Manuals.

The Office of the Interconnection shall prepare, maintain and update the PJM Manuals consistent with this Agreement. The PJM Manuals shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the LLC or any Member, and the public.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms,

and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

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

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

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

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

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

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

First Revised Sheet No. 339A
Superseding Original Sheet No. 339A

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

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: December 31, 2003

Effective: May 1, 2004

the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

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

1.7.7 Pricing.

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

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule.

1.7.9 Delivery to an External Market Buyer.

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

1.7.10 Other Transactions.

(a) Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Capacity Resources available for dispatch by the Office of the Interconnection. Bilateral arrangements that contemplate the physical transfer of energy to or from a Market Participant shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

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

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

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

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

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

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

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

1.7.11 Emergencies.

- (a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.
- (b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This paragraph shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: September 1, 2004

Effective: October 1, 2004

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

First Revised Sheet No. 343A
Superseding Original Sheet No. 343A

1.7.12 Fees and Charges.

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

1.7.13 Relationship to the PJM Region.

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

1.7.14 PJM Manuals.

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

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 Operating Reserves.

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

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: March 31, 2008

Effective: May 30, 2008

in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output; or 2) ~~the resource has obtained an exception under the procedures specified in Section B.7 of the Appendix to Attachment Ma physical problem at the unit requires a risk premium, provided that the risk premium is approved by the MMU. The foregoing notwithstanding, the Office of the Interconnection and the MMU shall consider requests by nuclear generation resources for Operating Reserve payments for specific circumstances not covered by the foregoing rules. Such requests shall be evaluated on a case-by-case basis.~~

1.7.18 Regulation.

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

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

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned.

(d) A generation unit capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy limits of that generation unit, in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit.

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

1.7.19 Ramping.

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

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals

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

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

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

1.7.20 Communication and Operating Requirements.

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

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

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

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

First Revised Sheet No. 347A
Substitute Original Sheet No. 347A

Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

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

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

1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process.

1.8.1 PJM Dispute Resolution Agreement.

Subject to the condition specified below, any Member adversely affected by a decision of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market, including the qualification of an entity to participate in that market as a buyer or seller, may seek such relief as may be appropriate under the PJM Dispute Resolution Procedures on the grounds that such decision does not have an adequate basis in fact or does not conform to the requirements of this Agreement.

1.8.2 Market or Control Area Hourly Operational Disputes.

(a) Market Participants shall comply with all determinations of the Office of the Interconnection on the selection, scheduling or dispatch of resources in the PJM Interchange Energy Market, or to meet the operational requirements of the PJM Region. Complaints arising from or relating to such determinations shall be brought to the attention of the Office of the Interconnection not later than the end of the fifth business day after the end of the Operating Day to which the selection or scheduling relates, or in which the scheduling or dispatch took place, and shall include, if practicable, a proposed resolution of the complaint. Upon receiving

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

notification of the dispute, the Office of the Interconnection and the Market Participant raising the dispute shall exert their best efforts to obtain and retain all data and other information relating to the matter in dispute, and to notify other Market Participants that are likely to be affected by the proposed resolution. Subject to confidentiality or other non-disclosure requirements, representatives of the Office of the Interconnection, the Market Participant raising the dispute, and other interested Market Participants, shall meet within three business days of the foregoing notification, or at such other or further times as the Office of the Interconnection and the Market Participants may agree, to review the relevant facts, and to seek agreement on a resolution of the dispute.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

(b) If the Office of the Interconnection determines that the matter in dispute discloses a defect in operating policies, practices or procedures subject to the discretion of the Office of the Interconnection, the Office of the Interconnection shall implement such changes as it deems appropriate and shall so notify the Members Committee. Alternatively, the Office of the Interconnection may notify the Members Committee of a proposed change and solicit the comments or other input of the Members.

(c) If either the Office of the Interconnection, the Market Participant raising the dispute, or another affected Market Participant believes that the matter in dispute has not been adequately resolved, or discloses a need for changes in standards or policies established in or pursuant to the Operating Agreement, any of the foregoing parties may make a written request for review of the matter by the Members Committee, and shall include with the request the forwarding party's recommendation and such data or information (subject to confidentiality or other non-disclosure requirements) as would enable the Members Committee to assess the matter and the recommendation. The Members Committee shall take such action on the recommendation as it shall deem appropriate.

(d) Subject to the right of a Market Participant to obtain correction of accounting or billing errors, the LLC or a Market Participant shall not be entitled to actual, compensatory, consequential or punitive damages, opportunity costs, or other form of reimbursement from the LLC or any other Market Participant for any loss, liability or claim, including any claim for lost profits, incurred as a result of a mistake, error or other fault by the Office of the Interconnection in the selection, scheduling or dispatch of resources.

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.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

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 Capacity Resources in accordance with the Reliability Assurance Agreement, the Reliability Assurance Agreement-South, the Reliability Assurance Agreement-West, and the PJM Manuals and in consultation with the Members owning or controlling the output of Capacity Resources. A Market Participant 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 for a Generator Planned Outage of a 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. If the Office of the Interconnection withholds or withdraws approval, it shall coordinate with the Market Participant owning or controlling the resource to reschedule the Generator Planned Outage of the Capacity Resource 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 Participant 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 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.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 11, 2008

Effective: April 15, 2008

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Eighth Revised Sheet No. 350
Superseding Seventh Revised Sheet No. 350

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 11, 2008

Effective: April 15, 2008

(ii) If notice of a Transmission Planned Outage is not provided in accordance with the requirements in paragraph (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.

(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.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 11, 2008

Effective: April 15, 2008

(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 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 Market Participant may request approval for a Generator Maintenance Outage of any Capacity Resource from the Office of the Interconnection in accordance with the timetable and other procedures specified in the PJM Manuals. The Office of the Interconnection shall approve requests for

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 11, 2008

Effective: April 15, 2008

Generator Maintenance Outages for a 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.

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 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,

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: June 1, 2008

Issued On: June 30, 2008

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER07-1050 et al., issued May 30, 2008, 123 FERC 61,233 (2008).

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

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: February 1, 2006

Issued On: May 25, 2006

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER06-232-000 and ER06-232-001, issued April 25, 2006, 115 FERC ¶ 61,107.

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.

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: February 1, 2006

Issued On: May 25, 2006

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER06-232-000 and ER06-232-001, issued April 25, 2006, 115 FERC ¶ 61,107.

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,

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: November 18, 2005

Effective: February 1, 2006

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 and no-load fees may choose to submit such fees on either a market or a cost basis. Market Sellers must elect to submit both start-up and no-load fees 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 and no-load fees shall remain in effect without change throughout the applicable periods.

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

1.9.8 Transmission Owner Responsibilities.

All Transmission Owners shall regularly update and verify facility ratings, subject to review and approval by PJM, in accordance with the following procedures and the procedures in the PJM Manuals:

(a) Each Transmission Owner shall verify to the Operations Planning Department (or successor Department) of the Office of the Interconnection all of its transmission facility ratings two months prior to the beginning of the summer season (i.e., on April 1) and two months prior to the beginning of the winter season (i.e., on October 1) each calendar year, and shall provide detailed data justifying such transmission facility ratings when directed by the Office of the Interconnection.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 8, 2005

Effective: February 6, 2006

(b) In addition to the seasonal verification of all ratings, each Transmission Owner shall submit to the Operations Planning Department (or successor Department) of the Office of the Interconnection updates to its transmission facility ratings as soon as such Transmission Owner is aware of any changes. Such Transmission Owner shall provide the Office of the Interconnection with detailed data justifying all such transmission facility ratings changes.

(c) All Transmission Owners shall submit to the Operations Planning Department (or successor Department) of the Office of the Interconnection formal documentation of any procedure for changing facility ratings under specific conditions, including: the detailed conditions under which such procedures will apply, detailed explanations of such procedures, and detailed calculations justifying such pre-established changes to facility ratings. Such procedures must be updated twice each year consistent with the provisions of this section.

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, Reliability Assurance Agreement-South and Reliability Assurance Agreement-West.

(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) The Office of the Interconnection shall maintain an historical database of all transmission facility ratings, and shall review, and may modify or reject, any submitted change or any submitted procedure for pre-established transmission facility rating changes. Any dispute between a Transmission Owner and the Office of the Interconnection concerning transmission facility ratings shall be resolved in accordance with the dispute resolution procedures in schedule 5 to the Operating Agreement; provided, however, that the rating level determined by the Office of the Interconnection shall govern and be effective during the pendency of any such dispute.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: May 11, 2004

Effective: May 1, 2005

(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.

(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. Market Participants whose purchases and sales, and transmission customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified 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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

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.

1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral transaction in the Day-ahead Energy Market shall inform the Office of the

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: March 20, 2003

Effective: March 20, 2003

Interconnection if the parties to the transaction are not willing to incur Transmission Congestion Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;
 - ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and
 - iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.
- (d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generation Planned Outage, a Generator Maintenance Outage, or a Generation 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. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: June 1, 2008

Issued On: June 30, 2008

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER07-1050 et al., issued May 30, 2008, 123 FERC 61,233 (2008).

Interconnection's Offer Data specification, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: June 1, 2008

Issued On: June 30, 2008

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER07-1050 et al., issued May 30, 2008, 123 FERC 61,233 (2008).

Area outside the PJM Region. The foregoing offers:

- i) Shall specify the generation resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;
 - ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
 - iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;
 - 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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;
 - 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; and
 - viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour.
- (e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the MW of Regulation being offered, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

\$100 per MWh 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 heat rate increase resulting from operating a unit at lower MW output incurred from the provision of Regulation;
- ii. The cost increase (in \$/MW) in variable operating and maintenance costs resulting from operating the unit at lower MW output incurred from the provision of Regulation; and
- iii. An adder of up to \$12.00 per MW of Regulation provided.

Qualified Regulation capability must satisfy the 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 and no-load fees, 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.

(g) Each offer by a Market Seller of a Generation Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post on the PJM Open Access Same-time Information System 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer 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; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. 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).

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

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

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 3, 2008

Effective: May 30, 2008

the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-Ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy offer data submitted in the Day-Ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-Scheduled Resources.

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load 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.

(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 and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Appendix to Attachment K. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 30, 2008

Effective: June 1, 2008

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

1.10.3 Self-scheduled Resources.

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

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

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

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

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

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. 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

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: June 1, 2008

Issued On: June 30, 2008

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER07-1050 et al., issued May 30, 2008, 123 FERC 61,233 (2008).

Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for start-up or no-load fees.

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 dispatch 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. If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.

(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.

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: June 1, 2008

Issued On: June 30, 2008

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER07-1050 et al., issued May 30, 2008, 123 FERC 61,233 (2008).

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the load bus or busses 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 or credited at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing load bus or busses.

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

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

1.10.6A Transmission Loading Relief Customers.

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

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

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

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

1.10.7 Bilateral Transactions.

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

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers; (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,

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: September 1, 2004

Effective: October 1, 2004

as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier 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; (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.

(c) Following posting of the information specified in Section 1.10.8(b), 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. The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.

(d) Market Buyers shall pay and Market Sellers shall be paid for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

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, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation offer data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets 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.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

- 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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

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 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 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.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(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 entity controlling a 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.

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 Demand 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 Section 3.2.2.

(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 Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand 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 Demand Resources will be zero. If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand 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

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: June 1, 2008

Issued On: June 30, 2008

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER07-1050 et al., issued May 30, 2008, 123 FERC 61,233 (2008).

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 load 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 Demand 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 Section 3.2.3A.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Original Sheet No. 369A

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 load in the PJM

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

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.

1.12 Dynamic Scheduling.

(a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through dynamic scheduling of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A generating unit otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values for consideration in calculation of the Operating Reserve Credit shall not be so eligible if all of the output of the unit is dynamically scheduled outside of the PJM Region.

(b) An entity that owns or controls a generating resource outside of the PJM Region may request that the Transmission Provider electrically add all or part of the generating resource's output to the PJM Region through dynamic scheduling of the output to load inside the PJM Region. A generating unit otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values for consideration in calculation of the Operating Reserve Credit shall be so eligible only if all of the output of the unit is dynamically scheduled into the PJM Region.

(c) The Transmission Provider shall implement dynamic scheduling pursuant to a request under subsections (a) or (b) above, provided that the requesting entity can demonstrate to the satisfaction of the Transmission Provider that the requesting entity has arranged for the provision of signal processing and communications from the generator to the Office of the Interconnection and other participating control areas and remains in compliance with any other procedures and operational requirements established by the Office of the Interconnection regarding dynamic scheduling as set forth in the PJM Manuals.

(d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of firm or non-firm transmission service necessary to deliver the range of the dynamic transfer and any required ancillary services.

(e) The generating unit shall cooperate with PJM to ensure that changes in the dynamic schedule value do not adversely impact PJM's management of the PJM Area Control Error in a manner unacceptable to PJM, and, in the event that PJM, in its sole discretion, determines that the generating unit's actions in this regard are unacceptable, PJM may terminate the dynamic scheduling arrangement and may require such additional conditions as it deems appropriate prior to any further dynamic scheduling.

2. CALCULATION OF LOCATIONAL MARGINAL PRICES

2.1 Introduction.

The Office of the Interconnection shall calculate the price of energy at the load busses and generation busses in the PJM Region and at the interface busses between adjacent Control Areas and the PJM Region on the basis of Locational Marginal Prices. Locational Marginal Prices determined in accordance with this Section shall be calculated on a day-ahead basis for each hour of the Day-ahead Energy Market, and every five minutes during the Operating Day for the Real-time Energy Market.

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load at different locations in the PJM Region based on actual operating conditions existing on the

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: May 18, 2007

Effective: July 17, 2007

power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, 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. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are following economic dispatch instructions of the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices. Offers of demand reduction from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 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, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, 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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

produced by the State Estimator, which 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 busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine which resources are following its economic dispatch instructions. A resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-time Prices if:

- i) the applicable price bid by a Market Seller for energy from the resource is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located; or
- ii) the resource is specifically requested to operate by the Office of the Interconnection's dispatcher.

(c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the bid price associated with an energy offer by comparing the actual megawatt output of the resource with the Market Seller's offer price curve. Because of practical generator response limitations, a resource whose megawatt output is not ten percent more than the megawatt level specified on the offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region represented in the State Estimator and each interface bus between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying an incremental linear optimization method to minimize energy costs, given actual system conditions, a set of energy offers, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.

(b) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

2.6 Calculation of Day-ahead Prices.

For the Day-ahead Energy Market, day-ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained dispatch, model flows and system conditions resulting from the load specifications, offers for generation, dispatchable load, Increment Bids, Decrement Bids, offers for demand reductions, and bilateral transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system

conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Day-ahead Price at that bus.

2.7 Performance Evaluation.

The Office of the Interconnection shall undertake an evaluation of the foregoing procedures for the determination of Locational Marginal Prices, as well as the procedures for determining and allocating Financial Transmission Rights and associated Transmission Congestion Charges and Credits, not less often than every two years, in accordance with the PJM Manuals. To the extent practical, the Office of the Interconnection shall retain all data needed to perform comparisons and other analyses of locational marginal pricing. The Office of the Interconnection shall report the results of its evaluation to the Market Participants, along with its recommendations, if any, for changes in the procedures. The Office of the Interconnection shall prepare reports, with regard to participation of Economic Load Response Participants in the PJM Interchange Energy Market, as required by the FERC and the PJM Manuals.

3. ACCOUNTING AND BILLING

3.1 Introduction.

This schedule sets forth the accounting and billing principles and procedures for the purchase and sale of services on the PJM Interchange Energy Market and for the operation of the PJM Region.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Prices applicable to each relevant generation bus.

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Second Revised Sheet No. 374A
Superseding First Revised Sheet No. 374A

[Reserved]

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Third Revised Sheet No. 375
Superseding Second Revised Sheet No. 375

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

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

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

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

3.2.2 Regulation.

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

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day and the market-clearing price each hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in paragraph (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation each hour shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market. Estimated opportunity costs for Demand Resources to provide Regulation are zero.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: October 1, 2008

Effective: December 1, 2008

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Second Revised Sheet No. 377A
Superseding First Revised Sheet No. 377A

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Control Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation and shall be equal to the product of (i) the deviation of the generation resource's

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: October 1, 2008

Effective: December 1, 2008

output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: October 1, 2008

Effective: December 1, 2008

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource on an alternative basis determined in accordance with the procedure specified in Section IV.A of the Appendix to Attachment M. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller.

Comment [JWM1]: This covers the deletion of § 3.2.3(f-3) below.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

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

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

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

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

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

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

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where $URLMPP - UB$ shall not be negative.

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

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

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

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

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

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

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

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

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

~~(f-3) If a Market Seller can demonstrate to the satisfaction of the Office of the Interconnection and the Market Monitoring Unit that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection will negotiate with the individual Market Seller such appropriate compensation, subject to approval of such compensation by the Market Monitoring Unit.~~

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

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

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Regions, as defined in Section 3.2.3(q) of Appendix to Attachment K of this Agreement, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

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

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus;
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface;

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

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

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to all such deliveries for all Market Participants.

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this paragraph (m), the Effective Offer Price shall be the amount that, absent paragraphs

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: September 1, 2004

Effective: October 1, 2004

(l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatthours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to \$1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this paragraph (n), the Effective Offer Price shall be the amount that, absent paragraphs (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this paragraph, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed \$1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent paragraphs (l) and (n), would have been credited for Operating Reserves for such

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

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

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

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

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

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

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

where:

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

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is \leq 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must

also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Appendix to Attachment K of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP is less than the offer of the resource for at least four-5-minute intervals during one or more discrete hour periods during the relevant Operating Day.

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

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

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Appendix to Attachment K of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then paragraph (m) does not apply.

3.2.3A Synchronized Reserve.

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

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

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

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

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

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

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

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

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

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

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(1) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: May 30, 2006

Effective: September 8, 2006

achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day.

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

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

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

- (iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.
- (iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 30, 2008

Effective: June 1, 2008

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

3.2.3B Reactive Services.

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

Comment [JWM2]: This covers the deletion of § 3.2.3B(h) below.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 30, 2008

Effective: June 1, 2008

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

where:

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where $URTLMP - UB$ shall not be negative.

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

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

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

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

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

where $UB - URTLMP$ shall not be negative.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

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

~~(h) If a Market Seller can demonstrate to the satisfaction of the Office of the Interconnection and the Market Monitoring Unit that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection will provide such alternate lost opportunity cost compensation to the Market Seller as can be agreed upon by the Market Seller, the Office of the Interconnection and the Market Monitoring Unit.~~

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

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

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

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: July 2, 2004

Effective: September 1, 2004

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

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

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

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

3.2.7 Billing.

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

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

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

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

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding interface point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

The Office of the Interconnection shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.4 and/or 3.3A.5 of this Schedule, for demand reductions measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) by the MWs produced by on-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent highest load weekdays in the 45 calendar day period preceding the relevant load reduction event.

- i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:
 1. NERC holidays;
 2. Weekend days;
 3. Event days. For the purposes of this section an event day shall be any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;
 4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.
- ii. For the purposes of calculating the CBL for weekdays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (*i.e.* 60 days total including the relevant 45-day period):
 1. NERC holidays;
 2. Event day(s), as defined in subsection (a)(i)(3) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;
 3. Weekdays the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection;
 4. Any weekday the event period usage is less than 25% of the average event period usage for the five days.
- iii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iv) of this section.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

- iv. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

- i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:
 - 1. Event days. For the purposes of this section an event day shall be any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;
 - 2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
 - 3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

- ii. For the purposes of calculating the CBL for Saturdays or Sundays/NERC holidays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (*i.e.* 60 days total including the relevant 45 day period):
 1. Event day(s), as defined in subsection (b)(i)(1) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;
 2. Saturday or Sundays/NERC holidays where the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection.
- iii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iv) of this section.
- iv. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant, Load Serving Entity, electric distribution company, and/or the Office of the Interconnection (“Interested Parties”) may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer’s consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. Any proposal made pursuant to this section shall be provided to all other Interested Parties.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is received by all Interested Parties. If all Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon all Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.4 and 3.3A.5.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

- i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

- i. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Weather-Sensitive and Symmetric Additive Adjustment.

(a) Concurrent with submitting a Economic Load Response Registration Form to the Office of the Interconnection and annually thereafter, the Economic Load Response Participant shall notify the Office of the Interconnection whether it elects to apply the Weather-Sensitive Adjustment (or “WSA”) or Symmetric Additive Adjustment for the summer period (May-October) or the winter period (November-April). The Weather-Sensitive Adjustment either will decrease or increase Customer Baseline Load values. The Weather-Sensitive Adjustment may apply to measure load reductions in both the Real-time Energy Market and Day-ahead Energy Market, except that the simplified analysis for the summer period cannot be used with regard to the Day-ahead Energy Market. Unless an alternative formula is approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer, the Weather-Sensitive Adjustment and Symmetric Additive Adjustment shall be calculated using the following applicable formula:

Regression Analysis (available for the summer and winter period.)

Step 1: Perform a regression analysis in Excel using the slope & intercept functions between the end-use customer’s on-peak (8 AM to 8 PM), non-holiday, weekday hourly loads and the temperature-humidity index (“THI”) on a seasonal basis for the period the WSA is being applied.

The Office of the Interconnection will post on the Office of the Interconnection website a spreadsheet of the THI values for all relevant weather stations located within the PJM region.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

The regression analysis will produce a slope (m), expressing in kW/THI, and an intercept (b), expressed in kW, that describes the sensitivity of the end-use customer's load to weather.

Step 2: Determine the average THI for the on-peak hours for the five days used in the weekday CBL calculation.

Step 3: Determine the average THI for the on-peak hours of the event day.

Step 4: Calculate the WSA based on the following formula:

$$WSA = [(m \times THI_{EVENT DAY}) + b] / [(m \times THI_{CBL DAYS}) + b]$$

Simplified Analysis (available only for the summer period and for the Real-time Energy Market)

Step 1: Determine that the load is weather sensitive by agreement of the end-use customer, the Curtailment Service Provider, and the Load Serving Entity or by the Office of the Interconnection if there is no agreement. Weather adjustments could be negative or positive.

Step 2: Show that the hourly temperature reading at the nearest airport that provides weather information to the Office of the Interconnection equaled or exceeded 85 degrees Fahrenheit during each hour of the reduction event. The hourly temperature reading of another major airport nearby the end-use customer's location may be used if it can be shown that the temperature at the end-use customer's location correlates more closely.

Step 3: Calculate the average hourly load over two full hours beginning three hours prior to the Load Reduction Event.

Step 4: Calculate the average hourly load for the same hours using the values given by the CBL calculation.

Step 5: Compare the resulting average two hour loads from Steps 3 and 4.

Step 6: Determine if the difference from Step 5 expressed as a percentage is greater than 5 percent. If the difference is greater than 5 percent then the percentage will be the WSA for the reduction event.

Step 7: Submit an Excel spreadsheet to the Office of the Interconnection documenting the weather adjustment.

- The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.
- For end-use customers without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100 percent. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted in accordance with Steps 1-4 above.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

- In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the end-use customer's historical, seasonal, on-peak non-coincident peak load.

Symmetric Additive Adjustment

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Weather-Sensitive Adjustment calculations to the appropriate electric distribution company or Load Serving Entity for optional review. The electric distribution company or Load Serving Entity will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants participating in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The Economic Load Response Participant that curtails or causes the curtailment of demand in real-time will be compensated by the Office of the Interconnection the real-time Locational Market Price less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) In cases where the demand reduction is dispatched by the Office of the Interconnection, payment will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 17, 2008

Effective: June 17, 2008

Any shortfall will be made up through normal, real-time operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) An Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. However, in no event will the Economic Load Response Participant credit be reduced below zero on a daily basis.

(d) Economic Load Response Participants that have Locational Marginal Price based contracts pursuant to which they have agreed to pay their Load Serving Entity for the physical delivery of energy according to the hour value of the real-time Locational Marginal Price as calculated by the Office of the Interconnection, may choose to reduce demand and be compensated for the reduction in the Real-time Energy Market under the following circumstances. The Economic Load Response Participant shall provide the Office of the Interconnection with a strike price for the end-use customer's zonal Locational Marginal Price at which the end-use customer will reduce demand, as well as any start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the demand reduction must be committed. In cases where the Economic Load Response Participant's zonal Locational Marginal Price reaches the strike price and the demand reduction is dispatched by the Office of the Interconnection, the Office of the Interconnection shall pay such Economic Load Response Participant the difference between the actual savings achieved based on zonal Locational Marginal Price and the total value of the end-use customer's demand reduction bid. For purposes of this provision the total value of the demand reduction bid will be the sum of the strike price times the MW of reduction achieved during each hour of the time period the demand reduction was dispatched by the Office of the Interconnection or the minimum down-time whichever is greater, plus the submitted start-up costs. Demand reductions hereunder will not be eligible to set real-time Locational Marginal Price.

3.3A.5 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants participating in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection shall be paid the day-ahead Locational Marginal Price

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 17, 2008

Effective: June 17, 2008

less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall will be made up through normal, day-ahead operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit plus, if the real-time Locational Marginal Price is higher than the day-ahead Locational Marginal Price during the shortfall, the difference between the day-ahead and the real-time Locational Marginal Price times the shortfall.

(d) Economic Load Response Participants that have real-time Locational Marginal Price-based contracts may not participate in the Day-ahead Energy Market.

3.3A.6 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.4 and 3.3A.5 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market.

(b) Demand reductions that do not meet the requirements of Section 3.3A.6(a) shall not be eligible for settlement pursuant to Sections 3.3A.4 and 3.3A.5. Examples of settlements prohibited pursuant to this Section 3.3A.6(b) include, but are not limited to, the following:

- i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;
- ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;
- iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;
- iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint, provided that, the foregoing notwithstanding, settlements based on such demand reduction shall be allowed if the demand reduction alleviates congestion.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.7 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.4 and 3.3A.5 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.4 and 3.3A.5 are denied by the Office of the Interconnection more than 10% of the time.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.7. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: April 14, 2008

Effective: June 13, 2008

3.4 Transmission Customers.

3.4.1 Transmission Congestion Charges.

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

3.4.2 Transmission Loss Charges.

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

3.4.3 Billing.

The Office of the Interconnection shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Schedule, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Transmission Customer's internal accounting.

3.5 Other Control Areas.

3.5.1 Energy Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell energy to a Control Area interconnected with the PJM Region as necessary to alleviate or end an Emergency in that interconnected Control Area. Such sales shall be made (i) only to Control Areas that have undertaken a commitment pursuant to a written agreement with the LLC to sell energy on a comparable basis to the PJM Region, and (ii) only to the extent consistent with the maintenance of reliability in the PJM Region. The Office of the Interconnection may decline to make such sales to a Control Area that the Office of the Interconnection determines does not have in place and implement Emergency procedures that are comparable to those followed in the PJM Region. If the Office of the Interconnection sells energy to an interconnected Control Area as necessary to alleviate or end an Emergency in that Control Area, such energy shall be sold at 150% of the Real-time Price at the bus or busses at the border of the PJM Region at which such energy is delivered.

3.5.2 Operating Margin Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell Operating Margin to an interconnected Control Area as requested to alleviate an operating contingency resulting from the effect of the purchasing Control Area's operations on the dispatch of resources in the PJM Region. Such sales shall be made only to Control Areas that have undertaken a commitment pursuant to a written agreement with the Office of the Interconnection (i) to purchase Operating Margin whenever the purchasing Control Area's operations will affect the dispatch of resources in the PJM Region, and (ii) to sell Operating Margin on a comparable basis to the LLC.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

3.5.3 Transmission Congestion.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges as specified in Section 5.1.5 of this Schedule.

3.5.4 Billing.

The Office of the Interconnection shall prepare a billing statement each billing cycle for each Control Area to which Emergency energy or Operating Margin was sold, and showing the net amount to be paid by such Control Area. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts.

3.6 Metering Reconciliation.

3.6.1 Meter Correction Billing.

Metering errors and corrections will be reconciled at the end of each month by a meter correction charge (positive or negative). The monthly meter correction charge for tie meter corrections shall be the product of the positive or negative deviation in energy amounts, times the load weighted average real-time Locational Marginal Price for all hours of that month for all load buses in the PJM Region. The monthly meter correction charge for generator meter corrections shall be the product of the positive or negative deviation in energy amounts, times the generation weighted average Locational Marginal Price at that generator's bus for all hours of that month.

3.6.2 Meter Corrections Between Market Participants.

If a Market Participant or the Office of the Interconnection discovers a meter error affecting an interchange of energy with another Market Participant and makes the error known to such other Market Participant prior to the completion by the Office of the Interconnection of the accounting for the interchange, and if both Market Participants are willing to adjust hourly load records to compensate for the error and such adjustment does not affect other parties, an adjustment in load records may be made by the Market Participants in order to correct for the meter error, provided corrected information is furnished to the Office of the Interconnection in accordance with the Office of the Interconnection's accounting deadlines. No such adjustment may be made if the accounting for the Operating Day in which the interchange occurred has been completed by the Office of the Interconnection.

3.6.3 500 kV Meter Errors.

Billing shall be adjusted to account for errors in meters on 500 kV Transmission Facilities within the PJM Pre-Expansion Zones (excluding Allegheny Power) or between the PJM Pre-Expansion Zones (excluding Allegheny Power) and Allegheny Power. The Market Participant with the tie meter or generator meter experiencing the error shall account for the full amount of the discrepancy and an appropriate debit or credit shall be applied among Electric Distributors that report hourly net energy flows from metered tie lines in the Pre-Expansion Zones (excluding Allegheny Power) in proportion to the load consumed in their territories.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

3.6.4 Meter Corrections Between Control Areas.

An error between accounted for and metered interchange between a Party in the PJM Region and an entity in a Control Area other than the PJM Region shall be corrected by adjusting the hourly meter readings. If this is not practical, the error shall be accounted for by a correction at the end of the billing cycle. The Market Participant with ties to such other Control Area experiencing the error shall account for the full amount of the discrepancy. However, if the meter correction applies to a tie on the 500 kV system between the PJM Pre-Expansion Zones (excluding Allegheny Power) and other Control Areas, Electric Distributors that report hourly net energy flows from metered tie lines in the Pre-Expansion Zones (excluding Allegheny Power) shall account for the full amount of the discrepancy in proportion to the load consumed in their territories. The appropriate debit or credit shall be applied among Network Service Users in proportion to their deliveries to load served in the PJM Region. The Office of the Interconnection will adjust the actual interchange between the other Control Area and the PJM Region to maintain a proper record of inadvertent energy flow.

3.6.5 Meter Correction Data.

Meter error data shall be submitted to the Office of the Interconnection not later than noon on the third working day of the Office of the Interconnection after the end of the billing cycle applicable to the meter correction.

3.6.6 Correction Limits.

A Market Participant may not assert a claim for an adjustment in billing as a result of a meter error for any error discovered more than two years after the date on which the metering occurred. Any claim for an adjustment in billing as a result of a meter error shall be limited to bills for transactions occurring in the most recent annual accounting period of the billing Market Participant in which the meter error occurred, and the prior annual accounting period.

3.7 Inadvertent Interchange.

Inadvertent Interchange will be reconciled each hour by a charge allocation (positive or negative) applied to Network Service Users in proportion to their deliveries to load in the PJM Region, which shall be the product of the positive or negative Inadvertent Interchange amount times the PJM load weighted average Locational Marginal Price for that hour.

4. [Reserved For Future Use]

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

5. CALCULATION OF CHARGES AND CREDITS FOR TRANSMISSION CONGESTION AND LOSSES

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses in accordance with Section 9.3, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

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

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy market in the Day-ahead Energy market at the Day-ahead Congestion prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding interface point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation or interface buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

Point-to-Point Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery interface at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source interface at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source interface at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source interface at the boundary of the PJM Region. Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery interface and the Locational Marginal Price at what would be the source interface, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery interfaces in accordance with an applicable load flow study.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the interface busses between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by the Office of the Interconnection each hour will be the aggregate net amounts determined as specified in this Schedule. The Office of the Interconnection shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in [Section IV.B of the Appendix to Attachment M](#) ~~Section 5.2.1(b)~~, each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

~~(b) If a holder of a Financial Transmission Right between specified delivery and receipt busses acquired the Financial Transmission Right in a Financial Transmission Rights Auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt busses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in locational marginal prices in the Day-ahead Energy Market between such delivery and receipt busses is greater than the difference in locational marginal prices between such delivery and receipt busses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights Auction.~~

~~(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt busses that were acquired in the Financial Transmission Rights Auction.~~

5.2.2 Financial Transmission Rights.

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

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

is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

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

(d) A Financial Transmission Right, or the right to Transmission Congestion Credits attributable to a Financial Transmission Right, may be sold or otherwise transferred by agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM interchange energy market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

First Revised Sheet No. 396.01
Superseding Original Sheet No. 396.01

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

Issued By: Craig Glazer
Vice President, Government Policy

Effective: March 8, 2005

Issued On: January 7, 2005

Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER04-742 and EL04-105, issued May 28, 2004, 107 FERC ¶ 61,223.

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

First Revised Sheet No. 396A
Superseding Original Sheet No. 396A

[Reserved for future use.]

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: September 30, 2003

Effective: February 1, 2004

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

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subparagraph (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of *force majeure* that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subparagraph (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: January 22, 2007

Effective: March 1, 2007

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

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

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

- 1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.
- 2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.
- 3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: January 22, 2007

Effective: March 1, 2007

- 4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under paragraph (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.
- 5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: January 22, 2007

Effective: March 1, 2007

5.2.3 Target Allocation of Transmission Congestion Credits.

A target allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of the busses that comprise the Zone multiplied by the percent of annual peak load assigned to each node. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total target allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the target allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the target allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the target allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its target allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 “Distribution of Excess Congestion Charges.”

(b) If the total of the target allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its target allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

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

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR target allocations for the Planning Period + the sum of the ARR target allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total target allocation associated with all FTRs held by the Market Participant during the Planning Period.

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

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total target allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total target allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period. After Auction Revenue Right deficiencies are satisfied, any remaining excess Transmission Congestion Charges shall be distributed to Network Service Users and Transmission Customers purchasing Firm Point-to-Point Transmission Service in proportion to their Demand Charges for Network Service and their charges for Reserved Capacity for Firm Point-to-Point Transmission Service over such period.

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

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

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: $\{[\text{total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section}] * [\text{total target allocation for all FTRs held by the Market Participant at any time during the Planning Period}] / [\text{total target allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period}]\}$.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: March 19, 2008

Effective: May 18, 2008

5.3 Unscheduled Transmission Service (Loop Flow).

(a) When there are agreements between the Members (or the Office of the Interconnection on behalf of the Members) and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the total Transmission Congestion Charges that are distributed in accordance with Section 5.2.

(b) With respect to payments by the Office of the Interconnection to the New York Power Pool for the installation and operation of phase angle regulating facilities at Ramapo to control or limit unscheduled transmission service (loop flow), each of the following Transmission Owner with revenue requirements under the PJM Tariff shall pay a share of the charges on a transmission revenue requirements ratio share basis: *Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Power & Light Company, Potomac Electric Power Company, Public Service Electric and Gas Company, Rockland Electric Company, and UGI Utilities, Inc.*

5.4 Transmission Loss Charge Calculation.

5.4.1 Calculation by Office of the Interconnection.

The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer.

5.4.2 General.

(a) The basis for the Transmission Loss Charges shall be the differences in the Locational Marginal Prices, defined as the Loss Price at a bus, between points of delivery and points of receipt, as determined in accordance with Section 2 of this Schedule. (b) The Office of the Interconnection shall calculate Loss Prices in the form of Day-ahead Loss Prices and Real-time Loss Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.4.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases. The Transmission Loss Charge for deliveries from each such source shall be the Network Service User's hourly losses net bill.

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

(c) Generating Market Buyers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Loss Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data, if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Loss Charges at each Market Buyer's load bus to be charged for losses at Real-time Loss Prices determined by the product of the hourly Real-time Loss Prices at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Loss Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Loss Pricedetermined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Loss Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission loss payments at each Generating Market Buyer's generation bus to be paid at Real-time Loss Prices, determined by the product of the hourly Real-time Loss Price at the relevant bus times the

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Loss Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission losses that results from the Real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding interface point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Loss Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Loss Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation or interface buses, of the revenues at Day-ahead Loss Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.4.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

Point-to-Point Transmission Service. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source interface at the boundary of the PJM Region. Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source interface at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source interface at the boundary of the PJM Region. Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.

5.4.5 Total Transmission Loss Charges.

The total Transmission Loss Charges collected by the Office of the Interconnection each hour will be the aggregate net amounts determined as specified in this Schedule.

5.5 Distribution of Total Transmission Loss Charges.

The total Transmission Loss Charges accumulated by the Office of Interconnection in any month shall be distributed pro-rata to each Network Service User in proportion to its ratio shares of the total MWhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region and the total exports of MWhs of energy from such region during such month by all Transmission Customers.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

6. “MUST-RUN” FOR RELIABILITY GENERATION

6.1 Introduction.

Except as to the exempt generation resources identified in section 6.5 below, the following procedures shall apply to any generation resource subject to the dispatch of the Office of the Interconnection that, as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Region. The provisions of this Schedule shall otherwise apply to the scheduling, dispatch, operation and accounting treatment of such resources, to the extent not inconsistent with the provisions of this Section 6.

6.2 Identification of Facility Outages.

Not later than one hour prior to the deadline specified in Section 1.10.1 of this Schedule, the Office of the Interconnection shall identify on the PJM Open Access Same-Time Information System any facility outage or other system condition which it has determined may give rise to a transmission constraint that may require, in order to maintain system reliability, the dispatch of one or more generation resources that otherwise would not be dispatched based on the merits of their offers to the PJM Interchange Energy Market.

6.3 Dispatch for Local Reliability.

6.3.1 Request and Dispatch.

In addition to the dispatch of generation by the Office of the Interconnection to maintain reliability on transmission facilities monitored by it, a Member that owns or leases with rights equivalent to ownership local Transmission Facilities, as defined in this Agreement, and the Consolidated Transmission Owners Agreement and that operates a local control center in accordance with Section 11.3.3 of this Agreement or a Market Operations Center in accordance with Section 1.7.5 of this Schedule may request the Office of the

Interconnection to dispatch generation in order to maintain reliability on any such local Transmission Facilities that are not then monitored by the Office of the Interconnection, subject to the rules and procedures in Section 6.3.2 and the PJM Manuals. The Office of the Interconnection shall dispatch generation to maintain reliability on such local Transmission Facilities by incorporating the facilities in the State Estimator program described in Section 2.3 as set forth below, unless the Office of the Interconnection determines that such dispatch would adversely affect reliability in the PJM Region or would otherwise not be in accordance with Good Utility Practice.

6.3.2 Designation of Local Transmission Facilities.

The following rules and procedures shall apply to a Member request that the Office of the Interconnection dispatch generation on one or more local Transmission Facilities that are not then directly monitored by the Office of the Interconnection.

(a) The local Transmission Facilities that are the subject of the request for monitoring and dispatch control must be among the facilities that comprise the Transmission System under the PJM Tariff and must meet the PJM Reliability Planning Criteria set forth in the PJM Manuals;

(b) The Member shall provide modeling information for such local Transmission Facilities and provide sufficient telemetry to the Office of the Interconnection such that power flows are observable by the State Estimator program described in Section 2.3;

(c) The request for monitoring and dispatch control of local Transmission Facilities shall constitute a request that such local Transmission Facilities become and remain monitored by the Office of the Interconnection and subject to its dispatch control for a period of not less than one year;

(d) Requests under this section for monitoring and dispatch control of local Transmission Facilities may be made only annually pursuant to the procedures set forth in the PJM Manuals;

(e) The Office of the Interconnection shall post all requests for monitoring and dispatch control of local Transmission Facilities made under this section on the PJM Internet site; and

(f) The Member shall comply with all other operating procedures established by the Office of the Interconnection regarding dispatch for local reliability as set forth in the PJM Manuals.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: April 30, 2004

Effective: May 1, 2004

6.3.3 Transition Procedures for Local Transmission Facilities under the Monitoring Responsibility and Dispatch Control of the Office of the Interconnection as of June 1, 2002

The Office of the Interconnection shall determine whether local Transmission Facilities under its monitoring responsibility and dispatch control as of June 1, 2002 meet the PJM Reliability and Planning Criteria. Members with such local Transmission Facilities that do not meet the PJM Reliability Planning Criteria must either (1) remove the local Transmission Facilities from the dispatch control and monitoring responsibility of the Office of the Interconnection within 60 days of notification by the Office of the Interconnection of its determination that the local Transmission Facilities do not meet the PJM Reliability and Planning Criteria; or (2) commit, at their own cost and by a completion date agreed to by the Office of the Interconnection and the Member, to reinforce the local Transmission Facilities to enable the local Transmission Facilities to meet the PJM Reliability and Planning Criteria. This commitment to reinforce the local Transmission Facilities is subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, provided that, in the event that a Member cannot reinforce the local Transmission Facilities due to the unavailability of required financing, the local Transmission Facilities must be removed from the monitoring responsibility and dispatch control of the Office of the Interconnection within 60 days of the determination that required financing is unavailable. The local Transmission Facilities will remain under the monitoring and dispatch control of the Office of the Interconnection during the construction of the reinforcements.

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped at the levels specified below. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the transmission limit affects the schedule of the affected resource, and otherwise shall be capped for the entire Operating Day. The energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the offer price of such resource.

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

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

(d) [Reserved for Future Use]

(e) Except for the overall \$1,000 energy offer cap, offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any hour in which (1) there are not three or fewer generation suppliers available for redispatch under

subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the generation resource's owner, when combined with the two largest other generation suppliers, is not pivotal ("three pivotal supplier test"). ~~Notwithstanding the number of jointly pivotal suppliers in any hour, if the PJM Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer capping suspensions otherwise authorized by this section. Such proposals shall take effect only upon Commission acceptance or approval.~~

Comment [sk3]: See Section III.A. of the Appendix to Attachment M.

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

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

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

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

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Original Sheet No. 402.02

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: November 16, 2005

Effective: January 27, 2006

6.4.2 Level.

(a) The offer price cap shall be ~~one of the an~~ amounts determined in accordance with the procedures set forth in Section II.A of the Appendix to Attachment M and shall be provided by the Market Seller as a cost-based offer submitted in conjunction with any market offer specified below, as specified in advance by the Market Seller for the affected unit:

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

~~(ii) The incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals ("incremental cost"), plus 10% of such costs;~~

~~(iii) For units that are frequently offer capped, the following shall apply:~~

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

~~(b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be either (i) incremental cost plus 15%, not to exceed incremental cost plus \$40 per megawatt hour, or (ii) incremental cost plus \$30 per megawatt hour;~~

~~(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be (i) incremental costs plus 10%; (ii) incremental cost plus \$40 per megawatt hour; or (iii) the agreed unit specific going forward costs of the affected unit as reflected in an agreement entered pursuant to subparagraph (iv), below; or~~

~~(iv) An amount determined by agreement between the Office of the Interconnection and the Market Seller, provided that, if the Office of the Interconnection and the Market Seller cannot reach agreement after 60 days from the commencement of negotiations, then the Market Seller may submit the rates, terms, and conditions of its proposed offer cap to the Commission for resolution.~~

~~_____ (b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit that it is a “Frequently Mitigated Unit” or “FMU” because it was offer capped for the applicable percentage of its run hours, determined on a rolling 12 month average basis, effective with a one month lag.~~

~~_____ (c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an “Associated Unit” upon issuance of written notice from the Market Monitoring Unit that it meets all of the following criteria:~~

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

~~2. The unit (i) belongs to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder;~~

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

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

~~(d) For purposes of section 6.4.2(a)(iii)(c), the unit specific going forward costs determined by agreement between the Office of the Interconnection and the Market Seller shall include only the costs included in the Deactivation Avoidable Cost Rate, excluding costs associated with the Avoidable Project Investment Recovery Rate (APIR), set forth in section 115 of the PJM Tariff. Any costs that would be capitalized according to generally accepted accounting principles, associated carrying costs, or other fixed costs shall not be included. The agreement shall further provide that (i) in order for such costs to qualify for inclusion in the amounts determined by the agreement, the Market Seller~~

~~must agree to provide to PJM relevant cost data concerning fuel, operating and maintenance, and other avoidable costs, (ii) the maintenance practices and incurrence of expense at the unit shall be subject to audit by the Office of the Interconnection, and (iii) the unit owner agrees to operate the unit in accordance with Good Utility Practice.~~

~~(e) Any agreement entered pursuant to section 6.4.2(a)(iv) shall be filed with the Commission and shall be effective only upon acceptance of the agreement for filing by the Commission; provided however, that agreements to reflect unit specific going forward costs in accordance with section 6.4.2(a)(iii) shall be filed with the Commission for informational purposes only and shall be effective the day following the date of the informational filing.~~

~~(b)(4)~~ Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.5 [Reserved for Future Use]

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules

(a) Generation resources shall be subject to pre-determined limits on non-price offer parameters (“parameter limited schedules”) under the following circumstances:

- (i) The Operating Reserve markets fail the three pivotal supplier test. When this subsection applies, the parameter limited schedule shall be the less limiting of the defined parameter limited schedules or the submitted offer parameters.
- (ii) The Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared (“Maximum Generation Emergency Alert”); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert for all, or any part, of an Operating Day.

~~(b) Parameter limited schedules applied pursuant to this section shall be determined in accordance with the PJM Manuals and~~ shall consist of the following parameters:

- (i) Turn Down Ratio;
- (ii) Minimum Down Time;
- (iii) Minimum Run Time;
- (iv) Maximum Daily Starts;
- (v) Maximum Weekly Starts.

(c) Unless a Generation Resource has obtained an exception for unit-specific values determined in accordance with the process set forth in Section II.B.2 of the Appendix to Attachment M, such Generation Resource shall include in its parameter limited schedule values equal to or within the limits set forth in the chart below.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Second Revised Sheet No. 402A.01b
Superseding First Revised Sheet No. 402A.01b

| [\[Insert Parameter Limited Schedule Matrix\]](#)

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: September 25, 2008

Effective: December 1, 2008

6A Scarcity Pricing.

6A.1 Scarcity Conditions

6A.1.1 Commencement of Scarcity Conditions. Scarcity conditions that trigger scarcity pricing will occur when the Office of the Interconnection's system operators perform any one of the following identifiable, specifically defined actions for a Scarcity Pricing Region:

- a) Begin to dispatch online generators, which are partially designated as Maximum Emergency, into emergency output levels.
- b) Begin to dispatch online generators, which are designated entirely as Maximum Emergency, above their designated minimum load points, if they are currently online and operating at their minimum load points because of restrictive operating parameters associated with the generators.
- c) Begin to dispatch any offline generators that are designated entirely as Maximum Emergency and that have start times plus notification times less than or equal to 30 minutes.
- d) Voltage reduction action as described in the PJM Manuals.
- e) Emergency energy purchases pursuant to section 1.6.2(vi) of this Schedule.
- f) Manual load dump action as described in the PJM Manuals.

Whenever the Office of the Interconnection's system operators take any of the above designated actions triggering scarcity pricing, they shall post on the PJM website the emergency message describing the action and include in the posting the Scarcity Pricing Region for which the action is being taken.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 16, 2008

Effective: May 17, 2008

6A.1.2 Termination of Scarcity Conditions.

Scarcity pricing will be terminated in a Scarcity Pricing Region when demand and reserves can be fully satisfied with generation that is not designated Maximum Emergency. Under this condition, some generation that is designated Maximum Emergency may continue to operate due to timing limitations or operating limitations, but that generation is no longer needed under dispatch to satisfy system requirements, and scarcity pricing will no longer apply. Under no circumstances shall scarcity conditions be terminated if any of the following conditions remain in effect for the Scarcity Pricing Region:

- a) Voltage reduction action as described in the PJM Manuals.
- b) Emergency energy purchases from offers that do not have minimum purchase requirements of greater than 30 minutes duration attached to the offer.
- c) Manual load dump action as described in the PJM Manuals.

The Office of the Interconnection shall post on the PJM website the time when scarcity conditions are terminated.

6A.1.3 Maximum Emergency Offer Limitations.

For purposes of defining scarcity conditions, the Office of the Interconnection shall consider units that have been classified as Maximum Emergency only if they fall in one of the following categories:

- a) Environmental limits. If the unit has a hard cap on its run hours imposed by an environmental regulator that will temporarily significantly limit its availability.
- b) Fuel limits. If physical events beyond the control of the unit 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 unit owner.
- c) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the unit significantly limit its availability.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: November 16, 2005

Effective: January 27, 2006

- d) Temporary megawatt additions. If a unit 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 Office of the Interconnection shall post on its website the aggregate amount of generation megawatts that are classified as Maximum Emergency.

6A.2 Scarcity Pricing Regions.

6A.2.1 Established Scarcity Pricing Regions.

There shall be the following Scarcity Pricing Regions: (1) Entire Market Region consisting of all transmission zones in the PJM market; (2) Bedington-Black Oak Region consisting of all pricing nodes that have a 5% or greater positive power distribution factor (“dfax”) relative to the Bedington-Black Oak constraint; (3) the Eastern MAAC Region consisting of all pricing nodes that have a 5% or greater dfax relative to the Eastern Reactive Transfer constraint, (4) Eastern Market Region consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Bedington-Black Oak and the Central Reactive Transfer constraints; (5) the MAAC Region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Western Reactive Transfer constraint; and (6) the AP South Region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the AP South Reactive Transfer constraint.

6A.2.2 Annual Review of Scarcity Pricing Regions.

On an annual basis, PJM will review the defined Scarcity Pricing Regions and file changes (additions or deletions) to them with the Commission, as required. Additional Scarcity Pricing Regions must meet the following criteria: (1) consist of at least two entire transmission zones; (2) consist of contiguous transmission zones and sub-zones; (3) transmission import or transfer must be limited by EHV (500 kV or greater) constraints; and (4) consist of pricing nodes that have a 5% or greater positive dfax relative to the constraints.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 27, 2008

Effective: August 13, 2008

6A.2.3 Additional Temporary Scarcity Pricing Regions.

Additional temporary Scarcity Pricing Regions shall be designated by the Office of the Interconnection during the year when warranted by a non-transitory change in the topology of the transmission system. Additional temporary Scarcity Pricing Regions must meet the criteria set forth in section 6A.2.2. The Office of the Interconnection shall designate and post on the PJM website an additional temporary Scarcity Pricing Region within 72 hours of operational conditions warranting the additional temporary Scarcity Pricing Region. The temporary Scarcity Pricing Region shall become effective on the day following such posting, provided that the posting is before noon. If and when the topology is restored to its prior state or the change otherwise no longer warrants the designation of a temporary Scarcity Pricing Region, the Office of the Interconnection shall make a posting ending the additional designation. The termination of the temporary Scarcity Pricing Region shall become effective on the day following the posting, provided that the posting is before noon.

6A.3 Scarcity Pricing.

When scarcity conditions exist in a Scarcity Pricing Region, the region is considered incapable of meeting demand under normal economic dispatch conditions. Under such scarcity conditions, the Locational Marginal Prices of all nodes in a Scarcity Pricing Region will be determined based on the highest market-based offer price of all generating units operating under the Office of the Interconnection's direction to supply either energy or reserves on a real-time dispatch basis. No offer capping under section 6.4 of this Schedule may be initiated or continued in the Scarcity Pricing Region while scarcity pricing is in effect; provided, however, that generation in the Scarcity Pricing Region shall remain subject to the overall offer cap of \$1000 per megawatt-hour. During the period that scarcity pricing is in effect, the Office of the Interconnection's system operators may direct generating units in the Scarcity Pricing Region to reduce from their maximum output for system or local transmission control. In such event, such reductions shall be treated as reductions for reliability under which the generation supplier shall be entitled to opportunity cost compensation equal to the megawatt-hour reduction times the difference between the Locational marginal Price at the generator bus and the generation supplier's offer price consistent with section 3.2.3(f) of this Schedule. In addition, if a generator outside of a Scarcity Pricing Region is called upon to relieve the transmission constraint that caused the scarcity pricing condition in a Scarcity Pricing Region, then during the time that scarcity pricing is in effect in that Scarcity Pricing Region, that generation supplier shall be paid the higher of the generation-weighted Locational Marginal Price within the region determined as explained above or the price it otherwise would have been paid under this Schedule; however, that generation supplier's offer shall not be used to set Locational Marginal Prices in the Scarcity Pricing Region.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: August 3, 2006

Effective: June 1, 2007

7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS

7.1 Auctions of Financial Transmission Rights.

Annual, periodic and long-term auctions to allow Market Participants to acquire or sell Financial Transmission Rights shall be conducted by the Office of the Interconnection in accordance with the provisions of this Section.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: May 28, 2008

Effective: July 28, 2008

7.1.1 Auction Period and Scope of Auctions.

(a) The periods covered by auctions shall be: (1) the one-year period beginning the month after the final round of an annual auction; (2) any single calendar month period remaining in the Planning Period that is within the three, or less, month period immediately following the month that the monthly auction is conducted; (3) any Planning Period Quarter remaining in the Planning Period following the month that the monthly auction is conducted; and (4) the Planning Period Balance. In addition to the period defined in (2) of this subsection, only one of the periods defined in (3) or (4) of this subsection will be included in the monthly auction clearing until the Office of the Interconnection determines that both of the periods defined in (3) and (4) can be solved simultaneously in the same monthly auction process within the timeframe specified in Section 7.3.7. With the exception of FTRs allocated pursuant to section 5.2.2 (e) of this Schedule and the Financial Transmission Rights awarded as a result of the exercise of the conversion option pursuant to section 7.1.1(b) of this Schedule, in the annual auction, the Office of the Interconnection shall offer for sale the entire Financial Transmission Rights capability for the year in four rounds with 25 percent of the capability offered in each round. In the monthly auction, the Office of the Interconnection shall offer for sale in the auction any remaining Financial Transmission Rights capability for the months remaining in the Planning Period after taking into account all of the Financial Transmission Rights already outstanding at the time of the auction. In addition, any holder of a Financial Transmission Right for the period covered by an auction may offer such Financial Transmission Right for sale in such auction. On-Peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auctions. FTRs will be offered as Financial Transmission Right Obligations and Financial Transmission Right Options, provided that such Financial Transmission Right Obligations and Financial Transmission Right Options shall be awarded based only on the residual system capability that remains after the allocation of Financial Transmission Rights pursuant to section 5.2.2(e) and the award of Financial Transmission Rights pursuant to section 7.1.1(b) of this Schedule. Market Participants may bid for and acquire any number of Financial Transmission Rights, provided that all Financial Transmission Rights awarded are simultaneously feasible with each other and with all Financial Transmission Rights outstanding at the time of the auction and not sold into the auction. An ARR holder may self-schedule an FTR on the same path in the Annual FTR auction according to the rules described in the PJM Manuals.

(b) An Auction Revenue Rights holder may convert Auction Revenue Rights to Financial Transmission Rights. Such Financial Transmission Rights must (i) have the same source and sink points as the Auction Revenue Rights; (ii) be a 24-hour product; and (iii) be Financial Transmission Right Obligations. The Auction Revenue Rights holder must inform the Office of the Interconnection in accordance with the procedures established by the Office of the Interconnection that it intends to exercise the conversion option prior to close of round one of the

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: November 2, 2005

Effective: January 2, 2006

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Original Sheet No. 403.01

annual Financial Transmission Rights auction. Once the conversion option is exercised, it will remain in effect for the entire Financial Transmission Rights auction. The Office of the Interconnection will designate twenty-five percent of the megawatt amount of the Auction Revenue Rights to be converted as price-taker bids in each of the four rounds of the Financial Transmission Rights auction.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: November 2, 2005

Effective: January 2, 2006

An Auction Revenue Rights holder that converts its Auction Revenue Rights may not designate a price bid for its converted Financial Transmission Rights and will receive a price equal to the clearing price set by other bids in the annual Financial Transmission Right auction. To the extent a market participant seeks to obtain FTRs in the annual auction through such conversion, the FTRs sought will not be included in the calculation of such market participant's credit requirement for such annual FTR auction.

7.1.2 Frequency and Time of Auctions.

Subject to section 7.1.1 of this Schedule, annual Financial Transmission Rights auctions shall offer the entire FTR capability of the PJM system in four rounds with 25 percent of the capability offered in each round. All four rounds of the annual Financial Transmission Rights auction shall occur within the two-month period (April – May) preceding the start of the PJM Planning Period. Each round shall occur over five business days and shall be conducted sequentially. Each round shall begin with the bid and offer period. The bid and offer period for annual Financial Transmission Rights auctions shall be open for three consecutive business days, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time). Monthly, Financial Transmission Rights auctions shall be held each month. The bid and offer period for monthly Financial Transmission Rights auctions shall be open for three consecutive business days in the month preceding the first month for which Financial Transmission Rights are being auctioned, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 PM (Eastern Prevailing Time).

7.1.3 Duration of Financial Transmission Rights.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

7.1A Long-Term Financial Transmission Rights Auctions.

7.1A.1 Auctions.

(i) Subsequent to each annual FTR auction conducted pursuant to Section 7.1 of Schedule 1 of this Agreement, the Office of the Interconnection shall conduct a long-term FTR auction for the three consecutive Planning Periods immediately subsequent to the Planning Period during which the long-term FTR auction is conducted.

(ii) The capacity offered for sale in long-term FTR auctions shall be the residual system capability after the Annual Auction Revenue Rights allocations and annual FTR auction. In determining the residual capability the Office of the Interconnection shall assume that all Auction Revenue Rights allocated in the immediately prior annual Auction Revenue Rights allocation process are self-scheduled into FTRs, which shall be modeled as fixed injections and withdrawals in the long-term FTR auction.

7.1A.2 Frequency and Timing.

The long-term FTR auction process shall consist of two rounds. During the transition period when the long-term FTR auction process will be phased into PJM's market operations, the initial first round of the auction shall be conducted by the Office of the Interconnection approximately eight months prior to the start of the three Planning Period term covered by the first long-term FTR auction. The second round of the auction shall be conducted approximately two months after the first round. Thereafter, the first round shall be conducted by the Office of the Interconnection approximately 11 months prior to the start of the three Planning Period term covered by the relevant long-term FTR auction and the second round shall be conducted approximately 4 months after the first round. In each round 50% of total capacity available in the long-term FTR auction shall be offered for sale. Eligible entities may submit bids to purchase and offers to sell FTRs at the start of the bidding period in each round. The bidding period shall be three business days ending at 1700 on the last day. PJM performs the FTR auction clearing analysis for each round and posts the auction results on the MUI within five business days after the close of the bidding period for each round.

7.1A.3 Products.

(i) The periods covered by long-term FTR auctions shall be: (1) any single Planning Period within the three Planning Period term covered by the relevant auction; and (2) the three Planning Period term covered by the relevant auction.

(ii) On-Peak, off-peak and 24-hour FTR obligations, as defined in Section 7.3.4 of Schedule 1 of this Agreement, shall be offered in long-term FTR auctions; FTR options shall not be offered.

7.1A.4 Participation Eligibility.

(i) To participate in long-term FTR auctions an entity shall be a PJM Member or a PJM Transmission Customer. Eligible entities may submit bids or offers in long-term FTR auctions, provided they own FTRs offered for sale.

7.1A.5 Specified Receipt and Delivery Points.

Eligible sources and sinks in long-term FTR auctions shall be limited to hubs, zones, aggregates, generators, and interface buses.

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: July 28, 2008

Issued On: August 18, 2008

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER08-1016-000, issued July 25, 2008, 124 FERC ¶ 61,087.

7.2 Financial Transmission Rights Characteristics.

7.2.1 Reconfiguration of Financial Transmission Rights.

Through an appropriate linear programming model, the Office of the Interconnection shall reconfigure the Financial Transmission Rights offered or otherwise available for sale in any auction to maximize the value to the bidders of the Financial Transmission Rights sold, provided that any Financial Transmission Rights acquired at auction shall be simultaneously feasible in combination with those Financial Transmission Rights outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum MW quantities of the bids and offers, select the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

7.2.2 Specified Receipt and Delivery Points.

Auction bids for annual Financial Transmission Rights Obligations may specify as receipt and delivery points any combination of hubs, Zones, aggregates, generators, and interface buses. Auction bids for annual Financial Transmission Rights Options may specify as receipt and delivery points such combination of hubs, Zones, aggregates, generators, and interface buses as the Office of the Interconnection shall allow from time to time as set forth in its FTR business manual. Auction bids for Financial Transmission Rights submitted in the monthly auctions may specify as receipt and delivery points any combination of hubs, Zones, aggregates, generators, and interface buses for bids that cover any month beyond the next month, including bids that cover Planning Period Quarters or Planning Period Balance. Auction bids for Financial Transmission Rights submitted in the monthly auctions that cover the single calendar month period immediately following the month in which the monthly auction is conducted may specify any combination of receipt and delivery buses represented in the State Estimator model for which the Office of the Interconnection calculates and posts Locational Marginal Prices. Auction bids may specify receipt and delivery points from locations outside of the PJM Region to locations inside such region, from locations within the PJM Region to locations outside such region, or to and from locations within the PJM Region.

7.2.3 Transmission Congestion Charges.

Financial Transmission Rights shall entitle holders thereof to credits only for Transmission Congestion Charges, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than the Office of the Interconnection.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: November 2, 2005

Effective: January 2, 2006

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: November 2, 2005

Effective: January 2, 2006

7.3.2 Notice of Offer.

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

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

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

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

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

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: March 20, 2003

Effective: March 20, 2003

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

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

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

7.3.6 Determination of Winning Bids and Clearing Price.

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

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: November 2, 2005

Effective: January 2, 2006

flows into each interface point of the PJM Region and estimated scheduled transmission outages.

(b) In accordance with the requirements of Section 7.4.5 of this Schedule and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: December 31, 2003

Effective: May 1, 2004

from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.

(c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determined by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints.

7.3.7 Announcement of Winners and Prices.

Within two (2) business days after the close of the bid and offer period for an annual Financial Transmission Rights auction round, and within five (5) business days after the close of the bid and offer period for a monthly Financial Transmission Rights auction, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, the term and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at which each Financial Transmission Right was awarded. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell.

7.3.8 Auction Settlements.

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

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 19, 2007

Effective: August 21, 2007

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

(i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;

(ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their target allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;

(iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

(i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARR when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARR when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: May 28, 2008

Effective: July 28, 2008

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in paragraph (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: May 28, 2008

Effective: July 28, 2008

Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: July 3, 2006

Effective: March 1, 2007

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only zones, generators, hubs and external interface buses. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sunk to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in paragraph (f)

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated network resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated network resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: July 3, 2006

Effective: March 1, 2007

A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of the stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff (“Base Transmission Charge”). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the transmission service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the transmission service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subparagraph (i) shall not apply if the infeasibility is caused by

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

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A target allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right Auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total target allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily target allocations associated with all of the entity's Auction Revenue Rights.

(b) A target allocation of Residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The target allocation for Residual Auction Revenue Rights Credits shall be equal to MW amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligations in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily target allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights target allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the target allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its target allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 19, 2007

Effective: August 21, 2007

(b) If the total of the target allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights target allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their target allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Auction Revenue Right Credit target allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their target allocation.

7.5 Simultaneous Feasibility.

(a) The Office of the Interconnection shall make the simultaneous feasibility determinations specified herein using appropriate powerflow models of contingency-constrained dispatch. Such determinations shall take into account outages of both individual generation units and transmission facilities and shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction that are not inconsistent with the determination of the deliverability of Capacity Resources under the Reliability Assurance Agreement, Reliability Assurance Agreement-South or Reliability Assurance Agreement-West. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient revenues from Transmission Congestion Charges to satisfy all Financial Transmission Rights obligations for the auction period under expected conditions and to ensure that there are sufficient revenues from the annual Financial Transmission Right Auction to satisfy all Auction Revenue Rights obligations.

(b) On an annual basis the Office of the Interconnection shall conduct a simultaneous feasibility test for stage 1A Auction Revenue Rights, which shall assess the simultaneous feasibility for each year remaining in the term of the right(s). This test shall be based on the Auction Revenue Rights required to meet Zonal Base Load requirements. The Office of the Interconnection shall apply a zonal load growth rate to the simultaneous feasibility test for the ten year term of the stage 1A Auction Revenue Rights to reflect load growth as estimated by the Office of the Interconnection.

(c) Simultaneous feasibility tests for new stage 1 resource requests made pursuant to Section 7.6 of Schedule 1 of this Agreement shall ensure that the request for a new base resource does not increase the megawatt flow on facilities binding in the current Auction Revenue Rights allocation or in future stage 1A allocations and does not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions. The most limiting set of conditions will be used as the limiting condition in these evaluations. A simultaneous feasibility test conducted pursuant to this section by the Office of the Interconnection shall assess the simultaneous feasibility under the following conditions:

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: January 22, 2007

Effective: March 1, 2007

- Based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs.
- Based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

(d) Simultaneous feasibility tests conducted pursuant to this section shall be subject to Incremental Auction Revenue Rights granted pursuant to Section 7.8 of Schedule 1 of this Agreement and Section 46 of the PJM Tariff.

7.6 New Stage 1 Resources.

A Network Service User may request the addition of new stage 1 resources to the stage 1 resource list if the capacity of the historical generation resources for a Zone determined pursuant to Section 7.4.2(b) is less than the Zonal Base Load. Requests made pursuant to this section shall be subject to Section 7.5(c) of Schedule 1 of this Agreement and shall be limited to generation resources either owned by the requesting party or those subject to a bona fide firm energy and capacity supply contracts where such contract is executed by the requesting party to meet load obligations for which it is eligible to receive stage 1 Auction Revenue Rights and remains in force and effect for a minimum term of ten (10) years.

7.7 Alternate Stage 1 Resources.

A Network Service User may replace one or more of its existing stage 1 resources and its associated megawatt amount of Auction Revenue Rights determined pursuant to Section 7.4.2(b) with an alternate resource. If the Network Service User making such request accepts the megawatt amount of Auction Revenue Rights associated with the alternate resource as established by the Office of the Interconnection, the alternate resource shall replace the relevant existing stage 1 resource prospectively beginning with the next annual Auction Revenue Rights allocation. If the Network Service User making such request rejects the megawatt amount of Auction Revenue Rights established by the Office of the Interconnection for the alternate resource, the Auction Revenue Rights associated with the original stage 1 resource shall remain in effect for the Network Service User. Requests made pursuant to this section shall be subject to the following:

- Requests made pursuant to this section shall be subject to Section 7.5(c);
- Eligible alternate resources shall be limited to generation resources owned by the requesting party or bona fide firm energy and capacity supply contracts that meet the requirements set forth in Section 7.6 of Schedule 1 of this Agreement;

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: July 3, 2006

Effective: March 1, 2007

- Alternate resources shall be of an electrically equivalent megawatt amount, which means that relative to the existing resource, the alternate resource cannot consume a greater amount of transmission capability on facilities binding in the current Auction Revenue Rights allocation or future stage 1A allocations, and cannot allow megawatt flow(s) to exceed applicable ratings on any other facilities;
- The total amount of requested alternate stage 1 Auction Revenue Rights cannot exceed the original awarded stage 1 megawatt amounts of Auction Revenue Rights associated with the original historical resource as determined pursuant to Section 7.4.2(b).

7.8 Elective Upgrade Auction Revenue Rights.

(a) In addition to any Incremental Auction Revenue Rights (as defined in the PJM Tariff) established under the PJM Tariff, any party may elect to fully fund Network Upgrades (as defined in the PJM Tariff) to obtain Incremental Auction Revenue Rights pursuant to this section, provided that Incremental Auction Revenue Rights granted pursuant to this section shall be simultaneously feasible with outstanding Auction Revenue Rights, which shall include stage 1 and stage 2 Auction Revenue Rights, and against stage 1A Auction Revenue Right capability for the future 10 year period as determined by the Office of the Interconnection pursuant to Section 7.8(b) of Schedule 1 of this Agreement. A request made pursuant to this section shall specify a source, sink and megawatt amount.

(b) The Office of the Interconnection shall assess the simultaneous feasibility of the requested Incremental Auction Revenue Rights and the outstanding Auction Revenue Rights against the existing base system Auction Revenue Right capability and stage 1A Auction Revenue Right capability for the future 10 year period and based on this preliminary assessment it shall conduct studies to determine the upgrades required to accommodate the requested Incremental Auction Revenue Rights and ensure all outstanding Auction Revenue Rights are simultaneously feasible.

(c) If a party elects to fund upgrades to obtain Incremental Auction Revenue Rights pursuant to this section, no less than forty-five (45) days prior to the in-service date of the relevant upgrades, as determined by the Office of the Interconnection, the Office of the Interconnection shall notify the party of the actual amount of Incremental Auction Revenue Rights that will be granted to the party based on the allocation process established pursuant to Section 2.31 of Part VI of the Tariff.

(d) Incremental Auction Revenue Rights established pursuant to this section shall be effective for the lesser of thirty (30) years, or the life of the project, from the in-service date of the Network Upgrade(s). At any time during this thirty-year period (or the life of the Network Upgrade, whichever is less), in lieu of continuing this thirty-year Auction Revenue Right, the owner of the right shall have a one-time choice to switch to an optional mechanism, whereby, on an annual basis, it will have the choice to request an Auction Revenue Right during the annual Auction Revenue Rights allocation process between the same source and sink, provided the Auction Revenue Right is simultaneously feasible. A party that is granted Incremental Auction

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: March 28, 2008

Effective: May 27, 2008

Revenue Rights pursuant to this section may return such rights at any time, provided that the Office of the Interconnection determines that it can simultaneously accommodate all remaining outstanding Auction Revenue Rights following the return of such Auction Revenue Rights. In the event a party returns Incremental Auction Revenue Rights, it shall retain no further rights regarding such Incremental Auction Revenue Rights.

(e) No Incremental Auction Revenue Rights shall be granted pursuant to this section if the costs associated with funding the associated Network Upgrades are included in the rate base of a public utility and on which a regulated return is earned.

7.9 Residual Auction Revenue Rights

(a) As necessary in each Planning Period PJM shall calculate Residual Auction Revenue Rights for Auction Revenue Rights pathways that were prorated pursuant to section 7.4.2(h) of Schedule 1 of this Agreement. Residual Auction Revenue Rights calculated pursuant to this section shall be determined prior to the increase in transmission capability or the effect of any other relevant factor that creates the Residual Auction Revenue Rights.

(b) Network Service Users and Qualifying Transmission Customers allocated stage 1 Auction Revenue Rights pursuant to section 7.4.2(a)-(c) of Schedule 1 of this Agreement that were subject to proration pursuant to section 7.4.2(h) of Schedule 1 of this Agreement shall be eligible to receive Residual Auction Revenue Rights. Residual Auction Revenue Rights shall be allocated pursuant to the following schedule:

(i) The initial allocation of Residual Auction Revenue Rights shall be to holders of prorated stage 1A Auction Revenue Rights in an amount equal to the difference between the allocated stage 1A Auction Revenue Rights and the requested stage 1A Auction Revenue Rights.

(ii) Residual Auction Revenue Rights remaining after an allocation made pursuant to section 7.9(b)(i) of Schedule 1 of this Agreement shall be allocated to holders of prorated stage 1B Auction Revenue Rights in an amount equal to the difference between the allocated stage 1B Auction Revenue Rights and the requested stage 1B Auction Revenue Rights.

(iii) Residual Auction Revenue Rights remaining after allocations made pursuant to section 7.9(b)(i) and (ii) of Schedule 1 of this Agreement shall not be allocated to any entity and shall not be considered by the Office of the Interconnection in its administration of Section 7 of Schedule 1 of this Agreement.

(c) The sum of a Network Service User's and Qualifying Transmission Customer's Residual Auction Revenue Rights awarded pursuant to this section and its stage 1 and 2 Auction Revenue Rights awarded in an annual allocation shall not exceed the entity's peak load.

(d) Residual Auction Revenue Rights awarded pursuant to this section shall be effective on the first day of the month in a Planning Period the increase in transmission capability creating the Residual Auction Revenue Rights is included in the administration of section 7.1.1(a) of Schedule 1 of this Agreement.

(e) Residual Auction Revenue Rights awarded pursuant to this section shall be subject to section 7.4.2(e) of Schedule 1 of this Agreement.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 19, 2007

Effective: August 21, 2007

**8. INTERREGIONAL TRANSMISSION CONGESTION MANAGEMENT
PILOT PROGRAM**

8.1 Introduction.

The following procedures shall govern the redispatch of generation to alleviate transmission congestion on selected pathways on the transmission systems operated by the Office of the Interconnection and the New York ISO (“NYISO”). The procedures shall be used solely when, in the exercise of Good Utility Practice, the Office of the Interconnection or NYISO determines that the redispatch of generation units on the other’s transmission system would reduce or eliminate the need to resort to Transmission Loading Relief or other transmission-related emergency procedures.

8.2 Identification of Transmission Constraints.

(a) On a periodic basis determined by the Office of the Interconnection and NYISO, the Office of the Interconnection and NYISO shall identify potential transmission operating constraints that could result in the need to use Transmission Loading Relief or other emergency procedures in order to alleviate the transmission constraints, the need for which could be reduced or eliminated by the redispatch of generation on the other’s system.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: June 19, 2007

Effective: August 21, 2007

(b) In addition to the identification of such potential transmission operating constraints, the Office of the Interconnection and NYISO shall identify generation units on the other's system, the redispatch of which would alleviate the identified transmission constraints.

(c) From the identified transmission constraints, the Office of the Interconnection and NYISO shall agree in writing on the transmission operating constraints and redispatch options that shall be subject to Section 8 of this Schedule until otherwise agreed. In reaching such agreement, the Office of the Interconnection shall endeavor reasonably to limit the number of transmission constraints that are subject to Section 8 of this Schedule so as to minimize potential cost shifting among market participants in the control area of NYISO and the PJM Region resulting from the redispatch of generation under Section 8 of this Schedule. The Office of the Interconnection shall post the transmission operating constraints that are subject to Section 8 of this Schedule on PJM's internet site.

8.3 Redispatch Procedures.

If (i) a transmission constraint subject to Section 8 of this Attachment K – Appendix occurs and continues or reasonably can be expected to continue after the exhaustion of all economic alternatives that are reasonably available to the transmission system on which the constraint occurs and (ii) the Office of the Interconnection or NYISO, as applicable, has determined that it must either use Transmission Loading Relief or other emergency procedures, then (iii) the affected entity may request the other to redispatch one or more of the previously identified generation units to alleviate the transmission constraint. Upon such request, the Office of the Interconnection or NYISO, as applicable, shall redispatch such generation if it is then subject to its dispatch control and such redispatch is consistent with Good Utility Practice.

8.4 Locational Marginal Price.

(a) In the event that the Office of the Interconnection requests that NYISO redispatch generation under this Section 8, the Office of the Interconnection shall include the generator's offer price (in the NYISO energy market) in a reference price at the appropriate NYISO generator bus in the PJM State Estimator and in the calculation of Real-time Prices and shall include the cost of any applicable start-up and no-load fees in the cost of Operating Reserves for the Real-time Energy Market; provided, however, that if the energy offer price plus any applicable start-up or no-load fees exceeds \$1000/megawatt-hour, then the entire cost of the redispatch will be included in the cost of Operating Reserves for the Real-time Energy Market and will not be included in the Real-time Prices calculation.

(b) The redispatch of a generator by the Office of the Interconnection in response to a request from NYISO under Section 8 of this Schedule shall not be included in the determination of Locational Marginal Prices under Section 2 of this Schedule.

8.5 Generator Compensation.

Generators that have increased or decreased generation output above or below the level that would otherwise represent the economic dispatch level and as a result of a request made pursuant to this Section 8 (the "MWh Adjustment") shall be compensated based on the following:

(a) For a positive MWh Adjustment:

Payment to Generator = MWh Adjustment * (unit offer price – marginal price at the generator bus) + any applicable start-up or no-load costs not recovered by the marginal price

(b) For a negative MWh Adjustment:

Payment to Generator = |MWh Adjustment| * (marginal price at the generator bus – unit offer price) + any applicable start-up or no-load costs not recovered by the marginal price

8.6 Settlements.

(a) If NYISO redispatches generation under this Section 8, then the Office of the Interconnection shall include in its monthly accounting and billing a payment to NYISO for the costs of such redispatch as determined in accordance with Section 8.5.

(b) If the Office of the Interconnection redispatches generation under this Section 8, then it shall include in its monthly accounting and billing a credit to each redispatched generator calculated in accordance with Section 8.5. The Office of the Interconnection shall invoice NYISO and NYISO shall collect from its market participants and pay to the Office of the Interconnection on behalf of such market participants an amount equal to all such credits to generators.

(c) Unless there is a separate emergency energy transaction accompanying any generation adjustment under this Schedule 8, there shall be no adjustment in interchange between PJM and NYISO as a result of redispatch under this Schedule 8. In the event that an emergency energy transaction accompanies any generation adjustment, compensation for such transaction shall be at the rates for emergency purchases and sales which have been approved by the FERC, as they may be amended from time-to-time.

8.7 Effective Date.

Section 8 of this Schedule shall become effective only upon (a) approval or acceptance by the Federal Energy Regulatory Commission and (b) approval or acceptance by the Federal Energy Regulatory Commission of any comparable amendments to rate schedules of NYISO, if required.

9. COMMONWEALTH EDISON ZONE MARKET INTEGRATION DURING THE COMED INTEGRATION PHASE

9.1 Introduction.

The following procedures shall govern the application of the PJM Interchange Energy Market and related rules to the Zone of Commonwealth Edison Company and Commonwealth Edison Company of Indiana ("ComEd") during the period ("ComEd Integration Phase") beginning upon the date that the ComEd Zone is added to the PJM West Region and concluding upon the date that the zone of American Electric Power Company is added to the PJM West Region. During the ComEd Integration Phase, the zone of ComEd shall be a separate control area ("Northern Illinois Control Area") from the remainder of the PJM Region ("PJM Control Area"). The PJM Interchange Energy Market shall encompass both control areas, and all other provisions of this Agreement and its Schedules and Attachments shall apply to the Northern Illinois Control Area during the ComEd Integration Phase except to the extent expressly modified below.

9.2 Generation Transfer Pathway.

(a) A generation transfer pathway will be used to facilitate the application of the PJM Interchange Energy Market to the Northern Illinois Control Area. Transmission reservation holders with a valid existing transmission service reservation on the OASIS of American Electric Power Company ("Intermediate Transmission Provider"), where such reservation has a point of receipt or delivery in the Northern Illinois Control Area and a point of receipt or delivery in the PJM Control Area (in either direction) may allocate all or part of such reservation, in accordance with the following procedures, to the Office of the Interconnection for its exclusive use in administering the PJM Interchange Energy Market and conducting the security-constrained economic dispatch of resources to serve the loads of the PJM Region.

(b) Intermediate Transmission Provider reservation holders may submit requests on the Transmission Provider's OASIS to allocate firm transmission service to the pathway for monthly or annual periods, by no later than 11:00 a.m. eastern prevailing time ("EPT") on the day before the allocation is to commence. Monthly allocations shall commence at 00:00 EPT on the first day of a calendar month and end at 00:00 EPT on the first day of the next consecutive calendar month. Annual allocations shall commence at 00:00 EPT on the first day of a calendar year and end at 00:00 EPT on the first day of the next consecutive calendar year. All such requests must be pre-confirmed, and must identify the reservation holder's existing reservation from the Intermediate Transmission

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: December 31, 2003

Effective: May 1, 2004

Provider OASIS. The allocation may be for a quantity less than or equal to the existing Intermediate Transmission Provider reservation. Service allocated to the Office of the Interconnection may not be recalled by the reservation holder, or scheduled or redirected by the reservation holder on the Intermediate Transmission Provider's system, for the quantity or term of the allocation, but may be relied upon by the reservation holder to qualify a resource located in either of the two control areas in the PJM region during the Interim Period as a Capacity Resource to serve load in the other control area of the PJM Region. The Office of the Interconnection shall adopt such procedures as necessary to coordinate with the Intermediate Transmission Provider to ensure that the foregoing provision is enforced. The reservation holder remains responsible for all costs, charges, and obligations (financial or otherwise) under its transmission service agreement with the Intermediate Transmission Provider (excluding transmission losses, which shall be provided by the Office of the Interconnection in-kind pursuant to section 9.3 hereof) relating to the service being allocated.

(c) The allocated transmission service shall be under the exclusive use and control of the Office of the Interconnection and shall be employed to further its duties and responsibilities in accordance with the Operating Agreement, including, without limitation, the principles of section 7.7(i) of such Agreement. The Office of the Interconnection shall establish a dynamic schedule with the Intermediate Transmission Provider in either direction between the Northern Illinois Control Area and the PJM Control Area under the allocated transmission service to support the security-constrained, economic dispatch of resources to serve the loads of the PJM Region. In each direction, the dynamic schedule shall be subject to the quantity, duration, and priority of the transmission service allocated in such direction, and the dynamic schedule may be curtailed or limited by the Intermediate Transmission Provider in accordance with the terms and conditions of its governing tariff. The Office of the Interconnection shall treat curtailments of or limitations on the dynamic schedule in the same manner as transmission constraints internal to the PJM Region.

(d) Transmission Customers may not schedule as a single transmission transaction with the Office of the Interconnection point-to-point transmission service with a point of receipt (or delivery) at the border of the Northern Illinois Control Area and any third-party control area and a corresponding point of delivery (or receipt) at the border of the PJM Control Area and any third-party control area. Such service shall require (in addition to any necessary service from the Office of the Interconnection) transmission service from the Intermediate Transmission Provider or other appropriate transmission provider.

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: December 31, 2003

Effective: May 1, 2004

9.3 Transmission Loss Recovery.

The Office of the Interconnection shall be responsible for arranging for the generation of energy in, and its delivery from, the PJM Region to satisfy Intermediate Transmission Provider tariff requirements for recovery of transmission losses associated with allocated transmission service. The Office of the Interconnection shall apply the loss factors from the Intermediate Transmission Provider's tariff (including any variances in such loss factors between on-peak and off-peak periods, as defined in such tariff) to the quantity of energy dynamically scheduled to calculate the additional energy to be provided to the Intermediate Transmission Provider for in-kind satisfaction of transmission losses. The Office of the Interconnection shall adjust locational marginal prices in the PJM Region based on the adjusted dispatch necessary to generate the energy for Intermediate Transmission Provider losses and to compensate generators for supplying such additional energy.

9.4 Financial Transmission Rights.

(a) Financial Transmission Rights shall be allocated to Network Service Users and Firm Transmission Customers that take service that sources or sinks in the Northern Illinois Control Area in accordance with the provisions of section 5.2.2(f) and (g) of this Schedule applicable to new PJM zones; provided that, solely for purposes of allocating Financial Transmission Rights in the ComEd Zone during the term of the Phase-In Period, as such term is defined in Schedule 17 of the PJM West RAA, Financial Transmission Rights shall be allocated in the ComEd Zone in two stages: first, to all Firm Point-to-Point Transmission Customers and to all Network Integration Transmission Service paths for which the source point is a Capacity Resource or for which the original transmission service request identified a specific source; and, second, to the extent Financial Transmission Rights remain available after such allocation, to Network Integration Transmission Service paths for which there is no specifically designated source. The sum of the FTRs requested by a Load-serving Entity in both stages may not exceed the Load-serving Entity's Network Integration Transmission Service peak load. FTR requests in the first stage for which the source point is a Capacity Resource may not exceed the capability of the resource, and requests in such stage that are based on reserved Network service from a specifically identified source must be from such source and may not exceed the capacity of such reservation. The Office of the Interconnection shall identify in the PJM Manuals appropriate points of interconnection between the Northern Illinois Control Area and adjacent control areas for purposes of designating points of receipt or delivery for Financial Transmission Rights. If a Network Service User is the buyer under a wholesale supply contract that specifies the Network Service User's load as the delivery point, the Network Service User may elect to assign to the seller under such wholesale supply contract, if such seller chooses to assume such right, the right to nominate FTRs as described above, solely for purposes of allocating Financial Transmission Rights in the ComEd zone during the Phase-In Period. Following the Phase-in Period, Financial Transmission Rights (or Auction Revenue Rights, as applicable) shall be allocated in accordance with section 5.2.2.

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: December 31, 2003

Effective: May 1, 2004

(b) Transmission reservation holders that allocate firm transmission service to the Office of the Interconnection in accordance with this section 9 may request Financial Transmission Rights (solely as obligations, and not as options) in return for such allocation, and such request shall be granted by providing Financial Transmission Rights between the border of the Northern Illinois Control Area Zone and the border of the PJM Control Area in the amount requested, provided that the request is for a megawatt amount equal to or less than the megawatt amount of the transmission service so allocated. Such Financial Transmission Rights shall be in the same direction as the allocated transmission service and for a term equal to the term of the transmission service allocation. Financial Transmission Rights from the border points for the allocated transmission service to the source or sink points in the PJM Region shall be granted to the extent not previously granted and to the extent simultaneously feasible in accordance with section 7.5.

9.5 Ancillary Services.

For purposes of applying the provisions of sections 3.2.2, 3.2.3, and 3.2.3A pertaining to regulation, operating reserves, and Synchronized Reserves, the Northern Illinois Control Area shall be deemed a Control Zone. The offer of a generation or Demand Resource located in the Northern Illinois Control Area for regulation, operating reserves, or Synchronized Reserve shall be cost-based, unless and until market-based pricing is authorized for such service in the Northern Illinois Control Area.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

10. PJM-FE INTERREGIONAL TRANSMISSION CONGESTION MANAGEMENT

(a) The Office of the Interconnection may from time to time enter into agreements with FirstEnergy Solutions Corp. (“FES”) providing procedures for the redispatch of generation resources to alleviate transmission congestion, for use solely when, in the exercise of Good Utility Practice, the Office of the Interconnection determines, absent any other effective market-based solutions available to it, that the redispatch of generation units on the FE transmission system would reduce or eliminate the need to resort to Transmission Loading Relief or other transmission-related emergency procedures. The Office of the Interconnection is authorized to incur costs as described herein on behalf of the Market Participants to obtain such redispatch, and shall allocate and recover such costs as described herein. Such cost recovery shall be limited to the costs incurred by the Office of the Interconnection pursuant to an agreement providing for the redispatch of generation resources at FE’s Sammis Generating Station to alleviate actual or contingency overloads on the PJM Wylie Ridge transformers (the #5 transformer or the #7 transformer) or the PJM Sammis-Wylie Ridge 345kV transmission line. The costs the Office of the Interconnection is authorized to incur and to recover hereunder to obtain such redispatch shall be those necessary to compensate for reasonable opportunity costs incurred by FE in connection with such redispatch as calculated based upon the cost of the energy that could have been produced by the Sammis units as developed in accordance with the PJM Cost Development Manual, as well as costs incurred by FE related to reduced efficiency caused by cycling its units at the request of the Office of the Interconnection.

(b) Any payments to FE associated with redispatch under section 10(a) shall be included in the cost of Operating Reserves for the Real-time Energy Market, in accordance with Section 3.2.3(g) of this Schedule 1.

Issued By: Craig Glazer
Vice President, Government Policy
Issued On: June 30, 2004

Effective: July 1, 2004

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Substitute Original Sheet No. 414
Superseding Original Sheet No. 414



PJM Emergency Load Response Program

Issued By: Craig Glazer
Vice President, Governmental Policy
Issued On: March 27, 2003

Effective: March 20, 2003

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Substitute First Revised Sheet No. 415
Superseding First Revised Sheet No. 415



Table of Contents

EMERGENCY LOAD RESPONSE PROGRAM	416
PARTICIPANT QUALIFICATIONS	416
METERING REQUIREMENTS	417
REGISTRATION	418
EMERGENCY OPERATIONS	419
VERIFICATION	419A
MARKET SETTLEMENTS	420
REPORTING	421
NON-HOURLY METERED CUSTOMER PILOT	421

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: Upon Implementation Date

Issued On: March 27, 2006

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER06-406-000, issued February 24, 2006, 114 FERC ¶ 61,201 (2006).



EMERGENCY LOAD RESPONSE PROGRAM

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency event. There are two options for participation in the Emergency Load Response Program:

- ◆ Full Program Option

Participants in the Full Program Option receive an energy payment for load reductions during an emergency event and an Active Load Management (“ALM”) credit pursuant to Schedule 5.2 of the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and the Reliability Assurance Agreement-South, as applicable.

- ◆ Energy Only Option

Participants in the Energy Only Option receive only an energy payment for load reductions during an emergency event.

PARTICIPANT QUALIFICATIONS

Two primary types of distributed resources are candidates to participate in either of the two options provided by the Emergency Load Response Program:

- ◆ On-Site Generators

These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.

- ◆ Load Reduction

A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

Issued By: Craig Glazer
Vice President, Federal Government Policy

Effective: Upon Implementation Date

Issued On: March 27, 2006

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER06-406-000, issued February 24, 2006, 114 FERC ¶ 61,201 (2006).



PJM membership is required to participate in either of the two options provided by the Emergency Load Response Program. Special membership provisions have been established for program participants in the Energy Only Option, as described below. The special membership provisions shall not apply to program participants in the Full Program Option. Any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the *PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.* However, for special members the \$5,000 annual membership fee, the \$1,500 application fee, and liability for Member defaults are waived, along with the following other modifications:

- Special Members are limited to be PJM market sellers;
- Voting privileges and sector designation are waived;
- Thirty day notice for waiting period is waived;
- Requirement for 24/7 control center coverage is waived;
- No PJM-supported user group capability is permitted.

To participate in either of the two options provided by the Emergency Load Response Program, the distributed resource must:

- Be capable of reducing at least 100 kW of load
- Be capable of receiving PJM notification to participate during emergency conditions.

To receive ALM Credits participants in the Full Program Option must satisfy the criteria set forth in Schedule 5.2 of the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and the Reliability Assurance Agreement-South, as applicable.

METERING REQUIREMENTS

The Load Response Program participants must have metering equipment that provides integrated hourly kWh values on an EDC account basis, that either meets the EDC requirements for accuracy or has a maximum error of two percent over the full range of the meter (including Potential Transformers and Current Transformers). The metering requirements can be met using either of the following two methods:

- Metering that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator).

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006



Metering that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an EDC account basis.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the CSP and verified by PJM with the EDC.

The installed meter must be one of the following:

EDC-owned hourly meter,

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read electronically by PJM, or

Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read by the customer (or the CSP), the readings from which are forwarded to PJM.

Nothing here changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

REGISTRATION

Participants must complete the PJM Emergency Load Response Program Registration Form ("Emergency Registration Form") that is posted on the PJM web site (www.pjm.com). The following general steps will be followed:

1. The participant completes the Emergency Registration Form located on the PJM web site.

PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. PJM also confirms with the appropriate LSE and EDC whether the load reduction is under other contractual obligations. Other such obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. The EDC and LSE have ten (10) business days to respond or PJM assumes acceptance.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006



2. PJM informs the requesting participant of acceptance into the program and notifies the appropriate LSE and EDC of the participant's acceptance into the program.

Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

EMERGENCY OPERATIONS

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of ALM Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM web site, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.

The Minimum Dispatch Price of a Full Program Option participant that reduces load may set the real time Locational Marginal Price ("LMP") provided that the participant's load reductions are needed to meet demand in the PJM Region. The Minimum Dispatch Price of an Energy Only Option participant that reduces load may set the real time LMP provided that such participant's load reductions are needed to meet demand in the PJM Regions and the Energy Only Option participant's resource satisfies PJM's telemetry requirements.

Operational procedures are described in detail in the *PJM Manual for Emergency Operations*.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006



VERIFICATION

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the event. If the data are not received within 60 days, no payment for participation is provided. Meter data must be provided for the hour prior to the event, as well as every hour during the event.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM. ~~All load reduction data are subject to PJM Market Monitoring Unit audit.~~

Comment [sk4]: See MMU proposed revised Attachment M § V.D

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006



MARKET SETTLEMENTS

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The minimum duration of a load reduction request is two hours. The magnitude of relief provided by Full Program Option participants shall be the amount PJM dispatches up to the kW amount declared on the Emergency Registration Form. The magnitude of relief provided by Energy Only Option participants could be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form.

PJM pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the applicable LMP. If, however, the sum of the hourly payments (excluding any ALM Credits) to a participant dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (*i.e.* Minimum Dispatch Price, minimum down time and shut down costs) then the participant will be made whole up to the offer value for its actual, achieved reductions.

Full Program Option participants that fail to provide a load reduction when dispatched by PJM shall be assessed the ALM Deficiency Charge specified in Schedule 11 of the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and Reliability Assurance Agreement-South, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases from the PJM energy market during the hour from day-ahead to real time.

Full Program Option participants that, prior to June 1, 2002, entered into contracts with LSEs or CSPs that enable participation in the Full Program Option, may participate in the Emergency Load Response program during ALM events as long as the customer's ALM contract explicitly excludes payment or credit for energy not consumed during ALM events.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006



If the LSE that submitted the Full Program Option participant for ALM credit indicates that such participant is not eligible for simultaneous credit under the Emergency Load Response program and ALM is called for concurrent with the Emergency Load Response program, then payments will be made to the participant according to the Emergency Load Response program only for the time during which ALM obligations were not in effect. Any response in excess of the contracted ALM amount will be compensated under the Emergency Load Response program for the entire duration of response.

In the event that a Full Program Option participant entered into an ALM contract with an LSE that enables participation in the Full Program Option after June 1, 2002, such participant shall be credited for load reductions pursuant to this Emergency Load Response Program, notwithstanding any terms or conditions contrary in the contract.

Program charges and credits will appear on the PJM Members monthly bill, as described in the *PJM Manual for Operating Agreement Accounting* and the *PJM Manual for Billing*.

REPORTING

Actual load reductions will be added back for the purpose of peak load calculations for capacity.

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM web site.

On an annual basis PJM will prepare a report that summarizes the status of the program and will submit it to the PJM Board of Managers, the Members Committee, the Reliability Committee, the Energy Market Committee, and the Operating Committee for review.

NON-HOURLY METERED CUSTOMER PILOT

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The customer or its Curtailment Service Provider or Load Serving Entity must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection ("Pilot Period"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006

PJM Interconnection, L.L.C.
FERC Electric Tariff
Sixth Revised Volume No. 1

Fourth Revised Sheet No. 421
Superseding Second Revised Sheet No. 421



Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

Issued By: Craig Glazer
Vice President, Federal Government Policy
Issued On: December 28, 2005

Effective: February 24, 2006