COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR APROVAL OF THE TERMS AND CONFITIONS OF THE RENEWABLE ENERGY PURCHAS AGREEMENT FOR BIOMASS ENERGY RESOURCES BETWEEN THE COMPANY AND ECOPOWER GENERATION-HAZARD LLC; AUTHORIZATION TO ENTER INTO THE AGREEMENT; GRANT OF CERTAIN DECLARATORY RELIEF; AND GRANT OF ALL OTHER REQUIRED APPROVALS AND RELIEF	)	Case No. 2013-00144

KENTUCKY POWER COMPANY RESPONSES TO

KIUC FIRST SET OF DATA REQUESTS

Volume 1 of 2

May 24, 2013

VERIFICATION

The undersigned, Gregory G. Pauley, being duly sworn, deposes and says he is the President and Chief Operating Officer for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Gregory G. Pauley

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2013-00144
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory G. Pauley, this the 17th day of May 2013.

Judy K. Rosquist 481393
Notary Public

My Commission Expires: January 23, 2017

VERIFICATION

The undersigned, Jay F. Godfrey, being duly sworn, deposes and says he is the Managing Director for Renewable Energy, for American Electric Power Service Corporation and he has personal knowledge of the matters set forth in the forgoing responses for which he is identified as the witness and that the information contained therein is true and correct to the best of his information, knowledge and belief.

Jay F. Godfrey

STATE OF OHIO)
) CASE NO. 2013-144
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jay F. Godfrey, this the 22nd day of May, 2013.

Notary Public

My Commission Expires: January 4, 2014

NOTARIAL SEAL STATE OF OHIO

Donna J. Stephens
Notary Public, State of Ohio
My Commission Expires 01-04-2014

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2013-00144
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 17th day of May 2013.

Judy K. Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Please describe how the EcoPower transaction opportunity was first presented to Kentucky Power. Specifically, was the transaction submitted in the context of a formal Kentucky Power solicitation for power supplies?

RESPONSE

EcoPower approached Kentucky Power asking if it would be willing to discuss the possibility of purchasing power from a yet to be built biomass facility. Kentucky Power had not requested any solicitation for power.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

If the EcoPower transaction was submitted in the context of a formal Kentucky Power solicitation for power supplies, please provide the original EcoPower proposal, all other proposals that were received, and all reports, analyses, and data associated with the evaluation of all of the proposals.

RESPONSE

N/A. See response to KIUC 1-1.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

If the EcoPower transaction was not submitted in the context of a formal Kentucky Power solicitation for power supplies please provide all notes, presentations, reports, analyses, and data associated with the initial meeting(s) where Kentucky Power was presented with the EcoPower transaction opportunity.

RESPONSE

The Company did not retain copies of the documentation provided by EcoPower during the initial meeting where the Company was presented with the EcoPower transaction opportunity.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Prior to a decision to commence negotiations, how did Kentucky Power evaluate the ecoPower transaction opportunity? Please provide all notes, presentations, reports, analyses, and data associated with such evaluation and the evaluation of any power supply alternatives.

RESPONSE

Please see the KIUC 1-4 Confidential Attachment 1 which was generated in connection with the Company's initial due diligence. Please also see the Company's response to KIUC 1-6.

WITNESS: Jay F Godfrey

ecoPower Generation LLC
Initial Due Diligence

AEP KENTUCKY POWER
A unit of American Electric Power

The following list of questions is being submitted to ecoPower Generation LLC (ecoPower) in preparation for an initial due diligence exercise related to ecoPower's proposed biomass project. This list is not comprehensive and has been established only to inquire upon minimal information that will be required for Kentucky Power and AEPSC to determine its potential interest in the ecoPower biomass project that is being proposed for construction near Hazard, Kentucky.

<u>General</u>

1. How many sites were evaluated prior to selecting the Hazard site? [redacted]
2. Are there any structures currently on the site? [redacted]
3. Are there any industrial facilities or residential neighborhoods nearby? [redacted]

4. What was the previous use of the site? [redacted]
5. Has a Phase I Environmental Site Assessment been completed? If so, please provide. If not, when will it be completed? [redacted]
6. Are there any known environmental issues associated with the selected site? [redacted]
7. How will ash and other by-products be handled? What is the storage capability for these by-products at the site for a 20-year term? [redacted]
8. Who will be providing O&M services? Please provide an organizational chart of the proposed staffing. [redacted]
9. What is the local community receptivity to the project? [redacted]

Project Development Team

10. Has the project development team developed, financed, and successfully constructed a power project similar to the proposed Hazard project? [redacted] What experience does the development team have with utility scale power projects? [redacted]

[redacted]

11. What experience does the development team have with utility scale power projects? [redacted]

12. What experience does the development team have with fluidized bed boilers? [redacted]

13. What experience does the development team have with biomass generation? [redacted]

Project Costs / Financing

14. What is the total CAPEX required? [redacted] What are the sources used to develop the estimate? [redacted] Have detailed balance of plant estimates been developed? [redacted] Are they available? [redacted]

15. What is the proposed source of the $60M in equity that is required to finance the project? [redacted]

What is their experience in the power sector? [redacted]

What is their familiarity with the proposed project and the financial estimates used to prepare the proposed price per MWh? [redacted]

[redacted]

16. Describe the terms and conditions of the $55M Bridge Loan to be secured by the U.S. Treasury grant program. [redacted]
17. Describe the source of the $135M senior debt financing and associated terms and conditions. [redacted]
18. What gives ecoPower confidence in the above financing structure and terms? [redacted] Has ecoPower retained an investment advisor? [redacted] If so, what is their experience with financing IPP projects? [redacted]
19. Describe the details associated with the $15M in state tax incentives from the Kentucky Economic Development Finance Authority. [redacted]
20. Provide a copy of the project's financial model. [redacted]
21. What is the projected interconnection upgrade costs? [redacted]

Fuel

22. Please provide ecoPower's projection of biomass fuel costs for the 20-year term. [redacted]
23. Per the ecoPower document, 40% of the fuel will come from PML (sister company). Describe the fuel plan for the remainder of the 60% of the fuel that will be required. [redacted]

[redacted]

24. What is PML currently doing with the wood waste (residual)? [redacted] What is their current inventory of wood waste? [redacted] What are costs associated with PML handling their waste? [redacted]

25. Please provide background information on the PML operation. [redacted]

26. If PML were to shut down, how would this impact the Hazard project? [redacted]

27. Describe ALL other options (sources) for fuel (i.e. rail, barge, etc.). [redacted]

28. Describe in detail the fuel that will be used in the process (btu, moisture, sulfur, ash, etc.). How much variability is there in the fuel with respect to btu and moisture? [redacted]

29. What is the planned inventory level? [redacted]

30. Describe the fuel processing steps required and the associated equipment required. Will all processing equipment be on-site? [redacted]

Project Schedule / Construction

31. Please submit a detailed project schedule. [redacted]

32. What is the lead time on the major equipment? [redacted]

33. When will major equipment be ordered? [redacted]

Technology

34. What experience does Shaw have with fluidized bed boilers? [redacted]

[redacted]

35. Has the major equipment (boiler, turbine, generator, etc.) been selected? [redacted] If so, please define. [redacted] If not, when will this equipment be selected?
36. List ALL fuels that the boiler will be capable of burning. [redacted]
37. Describe the pollution control technology that will be installed? [redacted]
38. Is the project planning to install or utilize any "used" equipment? [redacted] If so, please define.
39. Please describe where the "boiler" technology proposed has been used in an application using the specific fuel planned for the Hazard project. [redacted] How many years has this been in operation? [redacted] Reliability? [redacted] Issues? [redacted]
40. What is the design philosophy with respect to redundant (/backup) equipment? [redacted]

Interconnection

41. Please provide copies of the Feasibility and Impact Studies. [redacted]

[redacted] Were any significant issues identified in either of these studies? [redacted]

Financial Wherewithal / Credit Support

42. In all PPAs that AEP enters into, the counterparty either gives AEP a letter of credit or an investment grade rated corporate guarantee to support its obligations under the agreement. How would ecoPower plan to provide this credit support? [redacted]

Kentucky Power Company

REQUEST

Following the decision to commence negotiations, who provided the first draft of a term sheet or of the REPA (ecoPower or Kentucky Power)? Please provide that first draft.

RESPONSE

KPCo provided the first draft of the REPA to ecoPower. The first draft is provided as KIUC 1-5 Attachment 1. Confidential treatment is being sought for portions of Attachment 1.

WITNESS: Jay F Godfrey

THIS DRAFT DOCUMENT IS FOR DISCUSSION PURPOSES ONLY AND DOES NOT CONSTITUTE A BINDING OFFER NOR FORM THE BASIS FOR AN AGREEMENT BY ESTOPPEL OR OTHERWISE. THIS AND ANY SUBSEQUENT DRAFT DOCUMENT ARE SUBJECT TO NEGOTIATION AND MANAGEMENT AND BOARD REVIEWS AND APPROVALS (INCLUDING WITHOUT LIMITATION FINAL CREDIT AND LEGAL APPROVAL). ANY ACTIONS TAKEN BY A PARTY IN RELIANCE ON THE TERMS SET FORTH IN THESE WORKING DOCUMENTS OR ON STATEMENTS MADE DURING DISCUSSIONS OR NEGOTIATIONS OF THESE WORKING DOCUMENTS SHALL BE AT SUCH PARTY'S OWN RISK. UNTIL THE AGREEMENT IS FINALLY NEGOTIATED AND SIGNED BY BOTH PARTIES, NEITHER PARTY SHALL HAVE ANY LEGAL OBLIGATIONS WHATSOEVER TO THE OTHER PARTY, EXPRESSED OR IMPLIED, UNDER THESE WORKING DOCUMENTS OR OTHERWISE AS A RESULT OF SUCH DISCUSSIONS.

RENEWABLE ENERGY PURCHASE AGREEMENT
FOR
BIOMASS ENERGY RESOURCES

BETWEEN

ECOPOWER GENERATION-HAZARD LLC

AND

KENTUCKY POWER COMPANY

______________ ___, 2011

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RENEWABLE ENERGY PURCHASE AGREEMENT
BETWEEN
ECOPOWER GENERATION-HAZARD LLC
AND
KENTUCKY POWER COMPANY

This Renewable Energy Purchase Agreement (the "REPA") is made this ____ day of ________________, 2011 , by and between ecoPower Generation-Hazard LLC ("Seller"), a Kentucky limited liability company, with a principal place of business at 1256 Manchester Street, Lexington, Kentucky 40504, and Kentucky Power Company ("Purchaser"), a Kentucky corporation, with a principal place of business at c/o American Electric Power Service Corporation, 1 Riverside Plaza, Columbus, Ohio 43215-2355. Seller and Purchaser are hereinafter referred to individually as a "Party" and collectively as the "Parties".

INTRODUCTION

WHEREAS Seller desires to develop, design, construct, own or lease and operate a renewable electric generating facility with an expected total name plate capacity of approximately 58 MW, and which is further defined below as the "Facility"; and

WHEREAS Seller intends to locate the Facility at Perry County, Kentucky, and to interconnect the Facility with the Transmission Provider's System;

WHEREAS Seller desires to sell and deliver to Purchaser at the Point of Delivery all of the Facility's Renewable Energy Products, and Purchaser desires to buy the same from Seller; and

WHEREAS Purchaser has accepted Seller's offer to sell such Renewable Energy Products in accordance with the terms and conditions set forth in this REPA, subject to the timely receipt of all necessary regulatory and cost recovery approvals.

AGREEMENT

NOW THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

ARTICLE 1
DEFINITIONS AND RULES OF INTERPRETATION

1.1 Rules of Construction.

The capitalized terms listed in this Article shall have the meanings set forth herein whenever the terms appear in this REPA, whether in the singular or the plural or in the present or past tense. Other terms used in this REPA but not listed in this Article shall have meanings as commonly used in the English language and, where applicable, in Good Utility Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) The masculine shall include the feminine and neuter.

(B) References to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this REPA.

(C) The Exhibits attached hereto are incorporated in and are intended to be a part of this REPA; provided, that in the event of a conflict between the terms of any Exhibit and the terms of Articles 1 through 20 of this REPA, the terms of Articles 1 through 20 of this REPA shall take precedence.

(D) This REPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this REPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this REPA or any part hereof.

(E) The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this REPA. Unless expressly provided otherwise in this REPA, (i) where the REPA requires the consent, approval, or similar action by a Party, such consent, approval or similar action shall not be unreasonably withheld, conditioned or delayed, and (ii) wherever the REPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(F) Each reference in this REPA to any agreement or document (including those set forth electronically on an internet web site) or a portion or provision thereof shall be construed as a reference to the relevant agreement or document as amended, supplemented or otherwise modified from time to time.

(G) Each reference in this REPA to applicable laws and to terms defined in, and other provisions of, applicable laws (including those set forth electronically on an internet web site) shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time.

(H) Each reference in this REPA to a Person includes its successors and permitted assigns and, in the case of a Governmental Authority, any Person or Persons succeeding, in whole or in part, to its functions and capacities.

(I) In this REPA, the words "include," "includes" and "including" are to be construed as being at all times followed by the words "without limitation."

1.2 Interpretation with Interconnection Agreement.

The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider.

(A) The Parties acknowledge and agree that the Interconnection Agreement shall be a separate and free-standing contract and that the terms of this REPA are not binding upon the Interconnection Provider.

(B) Notwithstanding any other provision in this REPA, nothing in the Interconnection Agreement shall alter or modify Seller's or Purchaser's rights, duties and obligations under this REPA. This REPA shall not be construed to create any rights between Seller and the Interconnection Provider.

(C) Seller expressly recognizes that, for purposes of this REPA, the Interconnection Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Purchaser or an Affiliate of Purchaser.

1.3 Interpretation of Arrangements for Electric Supply to the Facility.

(A) The Parties recognize that this REPA does not provide for the supply of any electric service by Purchaser to Seller or to the Facility and Seller must enter into separate arrangements for the supply of electric services to the Facility, including the supply of turbine unit start-up and shutdown house power and Energy.

(B) The Parties acknowledge and agree that the arrangements for the supply of electric services to the Facility shall be separate and free-standing arrangements and that the terms of this REPA are not binding upon the supplier of such electric services.

(C) Notwithstanding any other provision in this REPA, nothing in the arrangements for the supply of retail electric services to the Facility shall alter or modify Seller's or Purchaser's rights, duties and obligations under this REPA. This REPA shall not be construed to create any rights between Seller and the supplier of such retail electric services.

(D) Seller expressly recognizes that, for purposes of this REPA, the supplier of retail electric services to the Facility shall be deemed to be a separate entity and separate contracting party whether or not the arrangements for the supply of retail electric services to the Facility is entered into with Purchaser or an Affiliate of Purchaser.

1.4 Definitions.

The following terms shall have the meanings set forth below when used herein:

"Abandonment" means, on and after the Commercial Operation Date, the relinquishment of all possession and control of the Facility by Seller, other than a transfer permitted under this REPA.

"Adjusted Renewable Energy" means, with respect to any Contract Year, the sum of (i) the amount of Renewable Energy delivered to Purchaser during such Contract Year, plus (ii) the sum of the Excused Deliveries during such Contract Year.

"Affiliate" of any named person or entity means any other person or entity that controls, is under the control of, or is under common control with, the named entity. The term "control" (including the terms "controls", "under the control of" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management of the policies of a person or entity, whether through ownership interest, by contract or otherwise.

"Ancillary Services" means regulation and frequency response services, energy imbalance services, automatic generating control, spinning reserve, non-spinning reserve, replacement reserve, reactive power, voltage support and any other services that support the transmission of capacity and energy or the reliable operation of the Transmission Provider's transmission system, all to the extent included as ancillary services in the Transmission Operator's open access transmission tariff, in each case, to the extent commonly sold or saleable and, in each case, to the extent that the assets comprising the Facility are Eligible to provide such services under normal operating conditions.

"Approval Application" means an application for an order from the Commission approving the terms and conditions of this REPA without modification and authorizing Purchaser to enter into this REPA.

"Approval Order" means a final, non-appealable order from the Commission approving the terms and conditions of this REPA without modification and authorizing Purchaser to enter into this REPA.

"Average Beneficial Environmental Interest Cost" means, for any Contract Year, the average cost over such Contract Year, expressed in \$/MWh, for Purchaser to purchase Comparable Renewable Energy Certificates in arms length, third party transactions with respect to such Contract Year, whether or not Purchaser actually purchases any such Comparable Renewable Energy Certificates, as further described in Exhibit I.

[redacted]

"Average Contract Rate" means, for any Contract Year, the weighted average Contract Rate (on a \$/MWh basis) payable under this REPA for such Contract Year, utilizing the percentage-weighting factors set forth on Exhibit I, and calculated as set forth on such Exhibit I.

"Back-Up Metering" shall have the meaning set forth in Section 5.4(C).

"Beneficial Environmental Interests" means all Non-Power Attributes associated in any way, directly or indirectly, with the Facility and all RECs associated with such Non-Power Attributes, excluding Renewable Energy Incentives and other federal, state or local tax credits, deductions and other tax benefits and financial incentives related to the ownership of the Facility or the sale to Purchaser of the output thereof.

"Biomass" means untreated organic material derived from plants or animals and available on a renewable basis, including: agricultural crops, crop by-products and residues; wood and paper manufacturing waste, including by-products of the wood manufacturing or pulping process, such as bark, wood chips, and sawdust; forestry waste and residues; other vegetation waste, including landscape or right-of-way trimmings; algae; food waste; animal wastes and by-products (including fats, oils, greases and manure); and biodegradable solid waste.

In addition, Biomass may include materials that are byproducts of preventive treatments (e.g., trees, wood) that are removed from forests to reduce hazardous fuels, to reduce or contain disease or insect infestation, or to restore ecosystem health; would not otherwise be used for higher value products; and are harvested from National Forest System land or public lands in accordance with public laws, land management plans, and requirements for old-growth maintenance.

In no case shall any Biomass fuel come from lands owned, managed or controlled by the Federal government or from the National Wilderness Preservation System, Wilderness Study Areas, Inventoried Roadless Areas, old growth stands, late successional stands, National Landscape Conservation System lands, National Monuments, National Conservation Areas, State Parks, Designated Primitive Areas, or Wild and Scenic Rivers corridors, except, in each case, for dead, severely damaged, or badly infested trees.

"Business Day" means any calendar day that is not a Saturday, a Sunday, or a NERC Holiday.

"Capacity" means the output level, expressed in MW, that the Facility, or the components of equipment thereof, is capable, as of a given moment, of continuously producing and making available at the Point of Delivery, taking into account the operating condition of the equipment at that time, the auxiliary loads and other relevant factors. Capacity includes all installed capacity and unforced capacity attributed to the Facility by the Transmission Operator, any regional reliability organization, Governmental Authority, or that is commonly sold or saleable to third parties.

"Capacity Resource" shall have the meaning set forth in the OATT.

[redacted]

[redacted]

"Capacity Shortfall" means, for any Delivery Year, the positive difference, if any, between the Committed UCAP and the actual UCAP for the Facility, as determined by PJM for such Delivery Year.

"Capacity Shortfall Liquidate Damages" means, for any Delivery Year, the sum of (i) the Capacity Resource Deficiency Charge for such Delivery Year and (ii) all Other Compliance Charges for such Delivery Year.

"Cash" shall have the meaning set forth in Section 11.1(C)(2).

"Clock Hour" means sixty-minute increments commencing at the top of the hour on the clock (i.e., 12 o'clock)

"Close of the Business Day" means 5:00 PM EPT on a Business Day.

"Commercial Operation" means the period beginning on the Commercial Operation Date and continuing through the Term of this REPA.

"Commercial Operation Date" or "COD" means the date that Seller provides notification to Purchaser, pursuant to Section 4.7, of Seller's declaration that all of the Conditions specified in Section 4.7 have occurred or otherwise been satisfied.

"Commercial Operation Milestone" means the anticipated Commercial Operation Date for the Facility. The Commercial Operation Milestone is specified as no later than December 31, 2013; provided, however, that the Commercial Operation Milestone shall be extended on a day-for-day basis for any delay in achieving the Commercial Operation Milestone resulting exclusively from Force Majeure.

"Commission" means the Kentucky Public Service Commission.

"Commissioned" means, with respect to the Facility, that the requirements of Section 4.7 have been satisfied.

"Committed Renewable Energy" shall have the meaning set forth in Section 7.2(A).

"Committed UCAP" shall have the meaning set forth in Section 7.2(D).

"Communications Equipment" means the communication circuits from the Facility to Purchaser for the purpose of telemetering, supervisory control and data acquisition and transmittal of real time data as described in either Exhibit H-1 or Exhibit H-2, at Seller's option, and voice communications as reasonably required by Purchaser.

"Comparable Renewable Energy Certificate" means any REC related to the Non-Power Attributes of a renewable energy generation facility newly constructed on and after August 30, 2007 that utilizes Biomass resources, wind power, landfill methane gas or other similar renewable resource, as reasonably designated by Purchaser, that is located in (i) Kentucky and interconnected to PJM and that is generated in the same year in which the Output Shortfall to which it is applicable occurs. Without limiting the generality of the foregoing definitions, Comparable Renewable Energy Certificates shall include certificates recognized by GATS as associated with the generation of biomass energy.

"Conditions" shall have the meaning set forth in Section 4.7.

"Consent and Agreement" means a Consent and Agreement in substantially the form of Exhibit N.

"Contract Administration Committee" means one representative each from Purchaser and Seller pursuant to Section 10.3.

"Contract Administration Procedures" means those procedures developed pursuant to Section 10.3.

"Contract Rate" means the applicable rate set forth in Exhibit C.

"Contract Year" means each full calendar year of the Term, whether such calendar year is comprised of 365 or 366 Days, commencing with the first calendar year subsequent to the year in which the Delivery Period commences, subject to the Proration Factor.

"Control Area" means the system of electrical generation, distribution, and transmission facilities within which generation is regulated in order to maintain interchange schedules with other such systems.

"Cost Recovery Approval Period" means the lesser of: (a) the expiration of six (6) months from the filing of the Cost Recovery Request; or (b) thirty (30) days after the receipt of final, non-appealable order denying a Cost Recovery Order.

"Cost Recovery Request" means a request filed with the Commission for a Cost Recovery Order.

"Cost Recovery Order" means a final, non-appealable order from the Commission authorizing Purchaser to recover fully all costs, rates, terms and conditions associated with this REPA and all other third party expenses associated with this REPA, if any, through Kentucky retail rates, which order is satisfactory to Purchaser in all respects in its sole discretion.

"Credit Rating" means, for any Person, the senior unsecured and non-credit-enhanced long term debt rating of such Person or, if such Person does not have a senior unsecured and non-credit-enhanced long term debt rating, the issuer rating of such Person.

"Creditworthy Bank" means a United States commercial bank or a foreign bank with a United States branch, which United States commercial bank or United States branch has at the applicable time a Credit Rating of (a) A- or better from Standard & Poor's Rating Services and (b) A3 or better from Moody's Investors Service, Inc.

[redacted]

"Day" means a calendar day.

"Delay Liquidated Damages" shall have the meaning set forth in Section 4.10.

"Delivery Period" means the period that commences at 0000 hours on the Commercial Operation Date and continues through the remainder of the Term.

"Delivery Year" means each period of June 1st through May 31st during the Delivery Period, subject to the Proration Factor.

"Dispute" shall have the meaning set forth in Section 13.9(A).

"Dispute Notice" shall have the meaning set forth in Section 13.9(A).

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

"EFORd" means, for any Delivery Year, the unavailability of the Facility due to a forced outage(s) or forced deratings when there is a demand on the Facility to generate, as determined by PJM in accordance with the PJM Manuals and Agreements (equation currently listed in PJM Generator Resource Performance Indices Manual (M-22)).

"Electric Metering Device(s)" means all meters, submeters, metering equipment, and data processing equipment used to measure, record, or transmit data relating to the Renewable Energy from the Facility.

"Eligible" means technically capable of production based on the then-existing design of the Facility (including equipment and interconnection) and under the OATT.

"Emergency" means an emergency condition as defined under the Interconnection Agreement or the OATT.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"Environmental Contamination" means the introduction or presence of Hazardous Materials at such levels, quantities or location, or of such form or character, as to constitute a violation of federal, state or local laws or regulations, and present a material risk under federal, state or local laws and regulations that the Site will not be available or usable for the purposes contemplated by this REPA.

"EPT" means Eastern Prevailing Time.

[redacted]

"Excused Event" means any Economic Curtailment, any Reliability Curtailment (other than as a result of Seller's acts or omissions described in clauses (iii) or (iv) of the definition thereof) and any Force Majeure event.

"Event of Default" shall have the meaning set forth in Article 12.

"Facility" means Seller's electric generating facility that uses Biomass exclusively to generate electricity and Seller's Interconnection Facilities, as identified and described in Article 3 and Exhibit B to this REPA, including all of the following, the purpose of which is to produce electricity and deliver such electricity to the Point of Delivery: Seller's equipment, buildings, all of the generation facilities, including boilers, generators, turbines, step-up transformers, output breakers, facilities necessary to connect to the Point of Delivery, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of the electric generating facility that produces the Renewable Energy subject to this REPA.

"Facility Capacity" means the Capacity capable of being generated from the Facility based on the aggregate nameplate rating of the boiler, turbine and the generator comprising the Facility, but shall not exceed 60 MW at any point during the Term.

"Facility Financing" means the obligations of Seller to any Facility Financier pursuant to the Financing Documents, including principal of, premium and interest on indebtedness, fees, expenses or penalties, amounts due upon acceleration, prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Facility Financing Representative" means, during any period when there is only one Facility Financier, the Facility Financier, and during any period when there is more than one Facility Financier, any trustee or agent on behalf of the Facility Financiers or such other single representative designated in writing by Seller.

"Facility Financiers" means, collectively, any lender(s) or any other financiers providing any Facility Financing .

"Failure to Extend Condition" shall have the meaning set forth in Section 11.1(C)(1).

"Failure to Replace Condition" shall have the meaning set forth in Section 11.1(D).

"Federal Funds Effective Rate" means the rate for that day opposite the caption "Federal Funds (Effective)" as set forth in the weekly statistical release designated as H. 15 (519), or any successor publication, published by the Board of Governors of the Federal Reserve System.

"FERC" means the Federal Energy Regulatory Commission.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements and other documents relating to the development, bridge, tax equity, construction or permanent debt financing for the Facility, including any credit enhancement, credit support, working capital financing, letter of credit facilities, and all such documents or agreements related to any refinancing or replacement of any of the foregoing, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Force Majeure" shall have the meaning set forth in Article 14.

"Forced Outage" means any condition at the Facility that requires unplanned removal of the Facility, or some part thereof, from service, another outage state, or a reserve shutdown state. This type of outage results from, among other things, immediate mechanical, electrical or hydraulic control system trips and operator-initiated trips in response to Facility conditions or alarms.

"GATS" means the Generation Attribute Tracking System administered by PJM Environmental Information Services, Inc. ("PJM-EIS") and providing environmental and emissions attributes reporting and tracking services to its subscribers in support of renewable portfolio standards and other information disclosure requirements that may be implemented by Governmental Authorities. GATS tracks generation attributes and the ownership of the attributes as they are traded or used to meet standards of Governmental Authorities.GATS includes any successor tracking system or systems with the same or similar purpose administered by PJM-EIS.

"GATS Certificates" means certificates recognized by GATS and associated with the generation of electricity from the Facility.

"Good Utility Practice(s)" means the practices, methods, and acts (including the practices, methods, and acts engaged in or approved by a significant portion of the power generation industry, the Transmission Operator or NERC) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, permits, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and expedition. Good Utility Practices are not intended to be the optimal practice, method or act to the exclusion of all others, but rather are intended to be any of the practices, methods or acts generally accepted for facilities similar to the Facility in the region in which the Facility is located during the relevant time period. With respect to the Facility, Good Utility Practice(s) includes taking reasonable steps to ensure that:

(A) equipment, materials, resources, and supplies, including spare parts inventories, are available in commercially reasonable quantities to meet the Facility's needs;

(B) sufficient operating personnel are available to operate the Facility on a 24 hour basis in accordance with reasonable industry operating practices for power generation equipment and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently, and in coordination with Purchaser and are capable of responding to reasonably foreseeable Emergency conditions whether caused by events on or off the Site;

(C) preventive, routine, and non-routine maintenance and repairs are performed on a basis that enables, to a commercially reasonable extent, reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(D) appropriate monitoring and testing are performed to determine that equipment is functioning in compliance with this REPA;

(E) equipment is not operated in a reckless manner, in violation of manufacturer's guidelines or in a manner unsafe to workers, the general public, or the interconnected system or in violation of applicable law; and

(F) equipment and components meet or exceed the standard of durability that is generally used for electric generation operations of this type in the region in which the Site is located and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site (which are not Force Majeure events) and under both normal and reasonably anticipated Emergency conditions (which are not Force Majeure events).

"Governmental Authority" means any federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power; or any court or governmental tribunal.

"Hazardous Materials" means any substance, material or particulate matter that is regulated by any Governmental Authority as an environmental pollutant or dangerous to public health, public welfare, or the natural environment including protection of nonhuman forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601); (ix) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a pesticide under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"Indemnified Party" shall have the meaning set forth in Article 17.

"Indemnifying Party" shall have the meaning set forth in Article 17.

"Interconnection Agreement" means the separate generation interconnection agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Transmission Provider's System, as such agreement may be amended from time to time.

"Interconnection Facilities" means the facilities necessary to connect Transmission Provider's System to the Point of Delivery, including breakers, bus work, bus relays, and associated equipment installed by the Interconnection Provider for the direct purpose of interconnecting the Facility, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. Arrangements for the installation and operation of the Interconnection Facilities shall be governed by the Interconnection Agreement.

"Interconnection Provider" means the Transmission Operator or any Transmission Provider responsible for the operation of the Interconnection Facilities and other equipment and facilities with which the Facility interconnects at the Point of Delivery.

"Issuer" means (a) with respect to a Security Fund in the form of a letter of credit or Cash, a Creditworthy Bank, or (b) with respect to a Security Fund in the form of a payment guaranty, a Creditworthy Entity.

"Locational Marginal Price" or "LMP" means the hourly integrated market clearing marginal price for Energy, including losses and congestion, at the Point of Delivery.

"MW" means megawatt, an amount of power equal to 1,000 kilowatts or 1,000,000 watts.

"MWh" means megawatt-hour, an amount of power equal to 1,000 kilowatt-hours or 1,000,000 watt-hours.

"NERC" means the North American Electric Reliability Corporation.

"NERC Holiday" means every Day other than a Saturday or Sunday which the NERC declares to be a holiday for power scheduling purposes.

"Net Replacement Energy Cost" means, for any Contract Year, the positive difference, if any, between (i) the Replacement Energy Cost (on a $/MWh basis) for such Contract Year and (ii) an amount equal to (a) the Contract Rate (on a $/MWh basis) for such Contract Year minus (b) the Average Capacity Value (on a $/MWh basis) for such Contract Year.

"Non-Power Attributes" means any characteristic of the Facility related to its benefits to the environment, including any avoided, reduced, displaced or off-set emissions of pollutants to the air, soil or water such as sulfur dioxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO), mercury (Hg), particulates, and any other pollutant that is now or may in the future be regulated under federal, state or local pollution control laws, regulations or ordinances or any voluntary rules, guidelines or programs; and further include any avoided emissions of carbon dioxide (CO_2) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere. Non-Power Attributes do not include Renewable Energy Incentives and other federal, state or local tax credits, deductions and other tax benefits and financial incentives related to the ownership of the Facility or the sale to Purchaser of the output thereof.

"OATT" means the FERC filed Open Access Transmission Service Tariff of the Transmission Operator, as it may be amended and approved by FERC.

"Operating Records" means operating logs, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that the Seller uses or maintains for the operation of the Facility.

"Other Compliance Charges" means any Peak-Hour Period Availability Charges, Generation Resource Rating Test Failure Charges, Peak Season Maintenance Compliance Penalty Charges, Load Management Event Penalty Charges and Daily Load Management Test Failure Charges, as such charges are defined in the PJM Manuals and Agreements (including any such charges under Schedule 9-5 (Capacity Resource and Obligation Management Service) and Schedule 9-6 (Management Service Cost) of the OATT.

"Output Shortfall" means, for any Contract Year, the positive difference (expressed in MWh), if any, between (i) the Adjusted Renewable Energy for such Contract Year and (ii) the Committed Renewable Energy for such Contract Year, as further described on Exhibit I.

"Output Shortfall Liquidated Damages" means, for any Contract Year, liquidated damages in the amount equal to the product of (i) the Output Shortfall for such Contract Year and (ii) the Net Replacement Energy Cost.

"Output Shortfall Notice Date" shall have the meaning set forth in Section 12.1(F).

"Penalties" means penalties imposed by Governmental Authorities.

"Person" means an individual, corporation, limited liability company, voluntary association, joint stock company, business trust, partnership, Governmental Authority, or other entity.

"PJM" means PJM Interconnection, LLC.

"PJM Manuals and Agreements" means, collectively, (i) all instructions, rules, procedures and guidelines established by PJM, (ii) all documents and protocols issued by PJM and (iii) all agreements to which Seller, Purchaser or any Affiliates of Purchaser, on the one hand, and PJM, on the other hand, are parties, either bilaterally or in concert with other entities, as may be in effect from time to time, in each case for the operation, planning, and accounting requirements of PJM and the PJM Interchange Energy Market, including the OATT.

"Point of Delivery" means the [ ] kV point, as shown on Exhibit G, at which point the quantities of Renewable Energy and Ancillary Services delivered are recorded and measured by the Interconnection Provider's revenue meters.

"Pre-Delivery Period Renewable Energy Production" means all Renewable Energy Products which are produced by the Facility prior to the commencement of the Delivery Period.

"Production Tax Credits" or "PTCs" means tax credits applicable to electricity produced from certain renewable resources pursuant to 26 U.S.C. § 45, or any substantially equivalent tax credits applicable to Seller based on its ownership or operation of the Facility or on the production and sale of Renewable Energy to the Purchaser.

"Proration Factor" means, if the Contract Year or Delivery Year in which the Delivery Period commences or the Contract Year or Delivery Year in which this REPA is terminated or expires is less than a full calendar year, then, with respect to such Contract Year or Delivery Year, an amount equal to a fraction, the numerator of which is the number of Days falling within the Delivery Period in such Contract Year or Delivery Year, and the denominator of which is 365 or 366, as applicable to the calendar year that includes such Contract Year or Delivery Year.

"Qualified Operator" means a Person that has (i) substantial experience in operating and maintaining electric generation facilities in the United States and (ii) met all applicable requirements under applicable law for operating and maintaining the Facility, including the requirements of the Transmission Operator. A Person will be deemed to have such substantial experience if it is a Person that has at least five (5) years of experience in operating and maintaining electric generation facilities in the United States.

[redacted]

"Renewable Energy" means the net electric Energy generated exclusively by the Facility from biomass and delivered to the Point of Delivery as measured by the Electric Metering Devices installed pursuant to Section 5.4. Renewable Energy shall be of a power quality of 60 cycle, three-phase alternating current that is compliant with the Interconnection Agreement.

"Renewable Energy Certificate" or "REC" means any credit, certificate, allowance or similar right that is related to the Non-Power Attributes of the Facility, whether arising pursuant to law, regulation, certification, markets, trading, off-set, private transaction, renewable portfolio standards, voluntary programs or otherwise. Without limiting the generality of the foregoing definitions, RECs shall include GATS Certificates.

"Renewable Energy Incentive" means: (a) federal, state, and local tax credits or other tax incentives associated with the construction, ownership, or production of electricity from the Facility (including Production Tax Credits, credits under Sections 38 and 45 of the Internal Revenue Code as in effect from time to time during the Term and any grants paid in lieu thereof); (b) any federal, state, and local governmental or nongovernmental payments, grants or other negotiable attributes relating in any way to the Facility or the output thereof; and (c) any other form of incentive that is not a Non-Power Attribute or Beneficial Environmental Attribute that is available with respect to the Facility.

"Renewable Energy Products" means, collectively, the Renewable Energy and Ancillary Services produced by the Facility and all of the associated Capacity, RECs and other Beneficial Environmental Interests.

"REPA" means this Renewable Energy Purchase Agreement between Seller and Purchaser, including the Exhibits attached hereto.

"Replacement Energy Costs" means, for any Contract Year, Purchaser's average cost of replacement Renewable Energy, or Energy plus Comparable Renewable Energy Certificates, over such Contract Year, calculated in accordance with part (c) of Exhibit I.

"Resale Costs" means the greater of (i) zero and (ii) an amount equal to (a) the net payments that Purchaser would have made to Seller for Renewable Energy Products purchased under this REPA at the applicable Contract Rate, but which Purchaser failed to purchase, less (b) the net amounts realized by Seller from the resale at the Point of Delivery of the Renewable Energy Products that Purchaser was required to accept in accordance with this REPA, but which Purchaser failed to do, adjusted for the cost of transmission of Energy incurred in connection with such resale, plus (c) directly associated transaction costs. Additional costs may include any Penalties incurred by Seller as a result of the Purchaser's non-performance that are recoverable under Section 20.3.

"RFC" means the Reliability*First* Corporation, one of the eight regional reliability councils approved by the North American Electric Reliability Corporation (NERC).

"Scheduled Outage/Derating" means a planned interruption or reduction of the Facility's generation by Seller that both (i) has been coordinated in advance with Purchaser, with a mutually agreed start date and duration, and (ii) is required for inspection, or preventive or corrective maintenance.

"Security Fund" means the fund that Seller is required to establish and maintain, pursuant to Section 11.1, as security for its performance under this REPA.

"Seller's Interconnection Facilities" means the equipment between the high side disconnect of the step-up transformer and the Point of Delivery, including all related relaying protection and physical structures as well as all transmission facilities required to access the Transmission Provider's System at the Point of Delivery, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. On the high side of the step-up transformer it includes Seller's load control equipment as provided for in the Interconnection Agreement. This equipment is located within the Site and is conceptually depicted in Exhibit B to this REPA.

"Site" means the parcel or parcels of real property on which the Facility will be constructed and located, including any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Section 3.2 and Exhibit B to this REPA.

"Tax" or "Taxes" shall have the meaning set forth in Section 20.2.

"Term" means the period of time during which this REPA shall remain in full force and effect, and which is further defined in Article 2.

[redacted]

"Transmission Operator" means PJM or any successor independent system operator, regional transmission operator or other transmission operator from time to time having authority to control the transmission Control Area to which the Facility is interconnected.

"Transmission Provider" means any Person or Persons that owns, operates or controls facilities used for the transmission of Energy from the Facility in interstate commerce.

"Transmission Provider's System" means the contiguously interconnected electric transmission facilities, including Interconnection Provider's Interconnection Facilities, over which the Transmission Provider has rights to provide for the bulk transmission of Capacity and Energy from the Point of Delivery.

"Unforced Capacity (UCAP)" means, with respect to any Delivery Year, the Installed Capacity (ICAP) of the Facility multiplied by a fraction, the numerator of which is one (1) and the denominator of which is the EFORd of the Facility, as determined by PJM in accordance with the PJM Manuals and Agreements (equation currently in Section 1.86 of the PJM Reliability Assurance Agreement).

ARTICLE 2
TERM AND TERMINATION

This REPA shall become effective as of the date of its execution, and shall remain in full force and effect until the date that is twenty (20) years after the day before the first day of the Delivery Period, subject to any early termination provisions set forth herein (the "Term"). Applicable provisions of this REPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this REPA, repayment of principal and interest associated with security funds, the indemnifications specified in this REPA, and the resolution of disputes between the Parties.

ARTICLE 3
FACILITY DESCRIPTION

3.1 Summary Description.

Seller shall endeavor to construct, own, operate, and maintain the Facility, which shall consist of a fluidized bed boiler, a steam turbine generator and associated equipment having an approximate designed maximum output of 60 MW. Exhibit B to this REPA provides a detailed description of the Facility, including identification of the equipment and components, which make up the Facility. The aggregate nominal or "nameplate" MW rating of the equipment comprising the Facility will not exceed 60 MW at any time during the Term. Any additional boilers or turbine-generator sets installed on the Site shall not comprise the Facility or share the same Point of Delivery or revenue meter used in connection with this REPA.

3.2 Location.

The Facility shall be located on the Site and shall be identified as Seller's Hazard Facility. The Facility is located in Perry County, Kentucky. A scaled map that identifies the Site, the location of the Facility at the Site, the location of the Point of Delivery and the location of the important ancillary facilities and Interconnection Facilities, is included in Exhibit B to this REPA.

3.3 General Design of the Facility.

Seller shall construct the Facility in accordance with Good Utility Practice(s), the Interconnection Agreement and rules of the Transmission Operator, including the PJM Manuals and Agreements. During Commercial Operation, Seller shall maintain the Facility according to Good Utility Practice(s) and the Interconnection Agreement. In addition to the requirements of the Interconnection Agreement, the design of the Facility shall at all times include metering accuracy current transformers and voltage transformers located at the Point of Delivery (or some other point mutually agreed to by the Parties) as required to connect to the Electric Metering Devices.

ARTICLE 4
COMMERCIAL OPERATION

4.1 Commercial Operation.

Subject to Sections 4.10, the Facility shall achieve the Commercial Operation Date, and shall be fully capable of reliably producing the Renewable Energy Products to be provided under this REPA and delivering such Renewable Energy Products to Purchaser at the Point of Delivery, no later than the Commercial Operation Milestone.

4.2 [Intentionally Omitted].

4.3 Site Report.

Seller shall conduct a Phase I environmental investigation of the Site and shall provide Purchaser, on or before sixty (60) days after the execution of this REPA, with a copy of the draft report summarizing such investigation, together with any data or information generated pursuant to such investigation.

4.4 Facility Contracts.

Seller shall provide to Purchaser, within thirty (30) Days after execution of this REPA, a certificate of an officer of Seller, in a form reasonably acceptable to Purchaser, stating that Seller has the boiler, turbine, and generator under contract to satisfy its obligations hereunder. Upon reasonable notice and request by Purchaser, Seller shall provide Purchaser with copies of major engineering drawings relating to the Facility. Information that is commercially sensitive, confidential or proprietary, as reasonably determined by Seller, may be redacted from the documents provided to Purchaser pursuant to this paragraph. All such information shall be treated as confidential information subject to Section 20.15 hereof. Seller shall provide sufficient information for Purchaser to be reasonably assured that Seller has contracted with financially responsible vendors as part of the Facility construction process.

4.5 Progress Reports.

Commencing upon the execution of this REPA, Seller shall submit to Purchaser, within the first fifteen (15) Days of each calendar month until the Commercial Operation Date is achieved, reports regarding development and construction progress in a form reasonably satisfactory to Purchaser. These progress reports shall describe the status of the development and construction of the Facility as of the end of the preceding month, including (a) a description of the progress of development and construction, (b) an explanation of any material changes in the development and construction schedule and (c) an estimate of the Commercial Operation Date. Commencing upon the date that is two months prior to the earlier of (x) the Commercial Operation Milestone and (y) the estimated Commercial Operation Date, Seller will additionally advise Purchaser weekly on the status of Facility Commissioning until the Commercial Operation Date is achieved.

4.6 Purchaser's Rights During Construction.

Purchaser shall have the right to monitor the construction, start-up and testing of the Facility, and Seller shall comply with all reasonable requests of Purchaser with respect to the monitoring of these events, provided, however, that Purchaser provides Seller reasonable advance written notice, shall not unreasonably interfere with or disrupt the activities of the Seller. Seller shall cooperate in such physical inspections of the Facility as may be reasonably requested by Purchaser during and after completion of construction. All persons visiting the Facility on behalf of Purchaser shall comply with all of Seller's applicable safety and health rules and requirements. Purchaser's technical review and inspection of the Facility shall not be construed as endorsing the design thereof nor as any warranty of safety, durability, or reliability of the Facility.

4.7 Conditions to Commercial Operation.

Seller shall notify Purchaser when the Facility has achieved the Commercial Operation Date, which notice shall not be unreasonably withheld or delayed by Seller. This notification is contingent upon Seller providing evidence reasonably acceptable to Purchaser of the satisfaction or occurrence of all of the conditions set forth in this Section 4.7 ("Conditions") and shall include a declaration by Seller to that effect. The Parties agree that review and approval of such Conditions may occur on an ongoing and incremental basis, pending resolution of any dispute, as such Conditions are satisfied. The Conditions are:

(A) Seller has successfully completed that testing of the Facility, which is required by the Financing Documents, the Facility's permits issued by Governmental Authorities, the Interconnection Agreement, Seller's operating agreements, Seller's engineering, procurement and construction ("EPC") agreement, and manufacturers' warranties for the commencement of commercial operations at the Facility;

(B) an officer of Seller, familiar with the Facility, has provided a list of the Facility's boiler, turbine, and generator, showing the make, model, serial number and designed maximum output (nameplate capacity) of each ;

(C) the Facility has achieved initial synchronization with the Transmission Provider's System;

(D) an independent professional engineer's certification has been obtained by Seller stating (i) that the Facility has been completed in all material respects (excepting punch list items that do not materially and adversely affect the ability of the Facility to operate as intended hereunder) in accordance with this REPA and (ii) the designed maximum output of each turbine/generator of the entire Facility, which total shall not exceed 60 MW;

(E) the interconnection of the Facility to the Transmission Provider's System has been completed in accordance with the Interconnection Agreement and has operated at a generation level acceptable to the Interconnection Provider in accordance with the operating requirements of the Interconnection Agreement;

(F) Seller has made all arrangements and executed all agreements required to deliver the Renewable Energy from the Facility to the Point of Delivery in accordance with the provisions of this REPA;

(G) [Intentionally Omitted];

(H) all arrangements for the supply of required electric services to the Facility, including the supply of turbine unit start-up and shutdown power and Energy, house power and maintenance power have been completed by Seller separate from this REPA, are in effect, and are available for the supply of such electric services to the Facility;

(I) the Security Fund meeting the requirements of Article 11 has been established;

(J) certificates of insurance evidencing the coverages required by Article 16 have been obtained and submitted to Purchaser;

(K) Seller has submitted to Purchaser a certificate of an officer of Seller familiar with the Facility after due inquiry stating that (i) all permits, consents, licenses, approvals, and authorizations required to be obtained by Seller from any Governmental Authority to construct and operate the Facility in compliance with applicable law and this REPA have been obtained and are in full force and effect, (ii) Seller is a PJM member, and (iii) Seller is in compliance with the terms and conditions of this REPA in all material respects;

(L) Seller has made all necessary filings and applications with Governmental Authorities for accreditation and participation in GATS and in any applicable federal certification program and state REC certification programs reasonably designated by Purchaser (including Kentucky, Ohio, Illinois, Maryland, Pennsylvania and West Virginia), pursuant to Section 10.9;

(M) Seller shall have provided the following items to Purchaser at least ninety (90) days prior to Commercial Operation: (1) the boiler, turbine, and generator layout and the generator manufacturer's power curve; and (2) a non-binding, good faith 12 month x 24 hour forecast of net Energy production from the Facility; provided that the data set forth in the foregoing item (1) above shall be updated and re-submitted to the Purchaser no later than five (5) Business Days after the Commercial Operation Date.;

(N) Seller shall have provided Purchaser with a copy of the final Phase I environmental report referred to in Section 4.3 and either (i) such report shall confirm that no conditions involving Environmental Contamination exist at or under the Site that would materially impact performance of Seller's obligations under this REPA or (ii) Seller shall provide to Purchaser prior to the Commercial Operation Date a remediation plan for removal of such Environmental Contamination; and

(O) Seller shall have established with PJM the node (virtual unit) described in Section 5.3(A).

4.8 Pre-Delivery Period Renewable Energy Production.

Seller shall coordinate the production and delivery of Pre-Delivery Period Renewable Energy Production with the Transmission Operator and be responsible for all scheduling activities and shall be entitled to all credits and charges associated with the delivery of such Pre-Delivery Period Renewable Energy Production into PJM for Seller's account. Purchaser shall cooperate with Seller to facilitate Seller's testing of the Facility necessary to satisfy the Conditions set forth in Section 4.7 as applicable.

4.9 QF Waiver.

For so long as this REPA is in effect, Seller waives, and agrees not to assert, the rights Seller may have against Purchaser to cause Purchaser to purchase or transmit energy or capacity pursuant to 18 C.F.R. section 292.303 or section 292.304 by virtue of the status of the Facility as a qualifying cogeneration facility as defined in the Public Utility Regulatory Policies Act of 1978, as amended.

4.10 Delay Liquidated Damages.

If Seller fails to meet the Commercial Operation Milestone, Seller shall pay damages to Purchaser on account of such delay ("Delay Liquidated Damages") in the amount of [redacted] commencing on the Day after the Commercial Operation Milestone and ending on the date that the Commercial Operation Date is achieved. Each Party agrees and acknowledges that (i) the damages that Purchaser would incur due to a delay in the achievement of the Commercial Operation Date by the Commercial Operation Milestone would be difficult or impossible to predict with certainty, (ii) the Delay Liquidated Damages contemplated by this provision are a fair and reasonable calculation of such damages, and (iii) the required payment by Seller of such Delay Liquidated Damages shall be Purchaser's sole remedy for such delay and the Facility's failure to achieve the Commercial Operation Date by the Commercial Operation Milestone. A delay in the Commercial Operation Date shall not be an Event of Default, except as provided in Section 12.1(E).

ARTICLE 5
DELIVERY AND METERING

5.1 Seller's and Purchaser's Obligations.

Subject to, and in accordance with, the terms and conditions of this REPA, Purchaser does hereby agree to purchase and pay for all of the Facility's Renewable Energy Products, and Seller does hereby agree to sell and deliver, or cause to be delivered, all of the Facility's Renewable Energy Products during the Delivery Period. Purchaser shall have the exclusive right to purchase and receive all of the Renewable Energy Products during the Delivery Period, with the exception of Energy produced by Seller for its own use at the Facility for station power. Seller shall not offer, sell or make available any of the Facility's Renewable Energy Products or dispatch any of the Facility's Renewable Energy Products to or for the benefit of Seller (except for its own use at the Facility for station power) or any other Person during the Delivery Period, other than to Purchaser.

5.2 Required Operation.

Except to the extent the Facility is actually unavailable or limited (including in accordance with Good Utility Practice(s) and due to curtailments under Section 7.4(A)), Seller shall operate the Facility to provide the Renewable Energy Products to Purchaser in all hours of the Delivery Period. Seller agrees that, notwithstanding anything herein to the contrary, Seller will not curtail or otherwise reduce deliveries of Renewable Energy Products in order to sell such Renewable Energy Products to other purchasers.

5.3 Delivery Arrangements.

(A) Prior to the Commercial Operation Date, Seller shall establish and shall maintain throughout the Term with PJM, a node (virtual unit) for purposes of identification of the Facility's Renewable Energy Products and the operating reserves and other charges and credits for which Seller is responsible under Section 5.6.

(B) Seller shall be responsible for all interconnection, electric losses, transmission and ancillary service arrangements and costs required to deliver the Renewable Energy and Pre-Delivery Period Renewable Energy Production from the Facility to Purchaser at the Point of Delivery. Purchaser shall be responsible for all electric losses, transmission and ancillary service arrangements and costs required to receive the Renewable Energy at the Point of Delivery and deliver such Energy to points beyond the Point of Delivery.

(C) Seller shall be responsible for paying any and all transmission upgrade costs identified by the Transmission Operator as Seller's responsibility in order to designate the Facility as a Capacity Resource.

5.4 Electric Metering Devices.

(A) Seller will comply with the terms and conditions of the Interconnection Agreement. The following provisions on Electric Metering Devices shall apply only to the extent they do not conflict with the performing Party's rights and obligations under the Interconnection Agreement or the OATT, as applicable.

(B) Seller shall provide Purchaser with reasonable advance notice of, and permit a representative of Purchaser to witness and verify, inspections and tests of the Electric Metering Devices, provided, however, that Purchaser shall not unreasonably interfere with or disrupt the activities of Seller and shall comply with all of Seller's safety standards. Upon request by Purchaser, Seller shall perform additional inspections or tests of any Electric Metering Device and shall permit a qualified representative of Purchaser to inspect or witness the testing of any Electric Metering Device, provided, however, that Purchaser shall not unreasonably interfere with or disrupt the activities of Seller and shall comply with all of Seller's safety standards. The actual expense of any such requested additional inspection of testing shall be borne by

Purchaser, unless upon such inspection or testing an Electric Metering Device is found to register inaccurately by more than the allowable limits established in this Article, in which event the expense of the requested additional inspection or testing shall be borne by Seller. If requested by Purchaser in writing, Seller shall provide copies of any inspection or testing reports to Purchaser.

(C) Purchaser and Seller each may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering") in addition to the Electric Metering Devices. Each Party, at its own expense, shall inspect and test its Back-Up Metering upon installation and at least annually thereafter. Each Party shall provide the other Party with reasonable advance notice of, and permit a representative of the other Party to witness and verify, such inspections and tests, provided, however, that the observing Party shall not unreasonably interfere with or disrupt the activities of the testing Party and shall comply with all of the testing Party's safety standards. Upon request by a Party, the other Party shall perform additional inspections or tests of its Back-Up Metering and shall permit a qualified representative of the requesting Party to inspect or witness the testing of such Back-Up Metering, provided, however, that the observing Party shall not unreasonably interfere with or disrupt the activities of the testing Party and shall comply with all of the testing Party's safety standards. The actual expense of any such requested additional inspection or testing shall be borne by the requesting Party, unless, upon such inspection or testing, the Back-Up Metering is found to register inaccurately by more than the allowable limits established in this Article, in which event the expense of the requested additional inspection or testing shall be borne by the testing Party. If requested by the requesting Party in writing, the testing Party shall provide copies of any inspection or testing reports to the requesting Party.

(D) If any Electric Metering Devices, or any Back-Up Metering, are found to be defective or inaccurate, they shall be adjusted, repaired, replaced, or recalibrated as near as practicable to a condition of zero error by the Party owning such defective or inaccurate device and at that Party's expense. The Party discovering such defect or inaccuracy shall promptly notify the other Party of such discovery.

5.5 Adjustment for Inaccurate Meters.

(A) The following provisions on Adjustment for Inaccurate Meters shall apply only to the extent they do not conflict with the performing Party's rights and obligations under the Interconnection Agreement or the OATT, as applicable.

(B) If an Electric Metering Device, or Back-Up Metering, fails to register, or if the measurement made by an Electric Metering Device, or Back-Up Metering, is found upon testing to be inaccurate by more than one percent (1.0%) from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements by the inaccurate or defective Electric Metering Device, or Back-Up Metering, for both the amount of the inaccuracy and the period of the inaccuracy, in the following manner:

(C) In the event that the Electric Metering Device is found to be defective or inaccurate, the Parties shall use the Back-Up Metering, if installed, to determine the amount of such inaccuracy, provided, however, that the Back-Up Metering has been tested and maintained in accordance with the provisions of this Article. If both Parties have installed Back-Up Metering, and the Back-Up Metering of both Parties is inaccurate by not more than one percent (1.0%) from the measurements made by the standard meter used in the test, the readings from the Back-Up Metering whose readings most closely conforms with the measurements made by the standard meter shall be used. In the event that neither Party has installed Back-Up Metering, or the Back-Up Metering is also found to be inaccurate by more than one percent (1.0%) from the measurement made by the standard meter used in the test, the Parties shall estimate the amount of the necessary adjustment on the basis of deliveries of Renewable Energy from the Facility during periods of similar operating conditions when the Electric Metering Device was registering accurately. The adjustment shall be made for the period during which inaccurate measurements were made.

(D) In the event that the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) the one hundred eighty (180) Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

(E) To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Purchaser, Purchaser shall use the corrected measurements as determined in accordance with this Article to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments by Purchaser for this period from such re-computed amount. If the difference is a positive number, the difference shall be paid by Purchaser to Seller; if the difference is a negative number, that difference shall be paid by Seller to Purchaser, or at the discretion of Purchaser, may take the form of an offset to payments due Seller by Purchaser (or by payment to Purchaser, if sufficient payments do not remain to offset). Payment of such difference by the owing Party shall be made not later than thirty (30) Days after the owing Party receives notice of the amount due, unless Purchaser elects payment via an offset.

5.6 Scheduling Arrangements.

The node established pursuant to Section 5.3(A) shall represent the Facility's account or Seller's (or Seller's agent's) market participant account, which for avoidance of doubt will contain solely those charges and credits related to the Facility, and the Parties will effectuate delivery and receipt of Renewable Energy Products at the Point of Delivery as follows:

(A) Seller will offer the Renewable Energy of the Facility into PJM utilizing a [day-ahead] forecast. Purchaser will have the right to review and audit Seller's day-ahead PJM offers.

(B) Seller will make appropriate, unilateral entries in PJM's eSchedule system at day-ahead LMP in a quantity for each day equal to the actual amount of Renewable Energy produced by the Facility on that day (as reflected in PJM's eMeter system).

(C) Seller will be responsible for all imbalance costs, operating reserves, congestion charges, losses and all other PJM charges incurred by Seller (or Seller's agent) in connection therewith and receive all credits, associated with the net difference between the day-ahead and real-time LMP associated with the deviation between the day-ahead award and offer under Section 5.6(A) and the actual amount of Renewable Energy produced by the Facility (as reflected in PJM's eMeter system).

(D) Seller shall be responsible for all costs related to delivery of Pre-Delivery Period Renewable Energy Production and Renewable Energy to the Point of Delivery or to the extent any such costs are incurred as a result of the failure by Seller to curtail deliveries in connection with a Reliability Curtailment or Economic Curtailment. Seller shall be responsible for all imbalance costs, operating reserves, congestion costs, losses and all other PJM charges incurred by Seller (or Seller's agent) and receive all associated credits, at the Point of Delivery and for delivery of the Renewable Energy or Capacity at and from the Point of Delivery, excluding any such costs arising from the failure by Seller to curtail deliveries in connection with a Reliability Curtailment or Economic Curtailment. To the extent either Party (or its agent) incurs costs or expenses which are the responsibility of the other Party under this Section 5.6, such costs or expenses shall be added to or shall be netted against the invoice for Renewable Energy.

(E) The parties will effectuate the delivery and receipt of Capacity from the Facility by timely making and confirming appropriate unit specific, bilateral transactions in PJM's eRPM system of "Unoffered Capacity" (*as defined in PJM Manual 18, PJM Capacity Market, Revision: 7, Effective: August 18, 2009*).

ARTICLE 6
CONDITIONS PRECEDENT

6.1 Purchaser's Condition Precedent.

(A) No later than ____ (__) days after execution of this REPA, Purchaser shall file an Approval Application with the Commission for approval by the Commission of this REPA. If the Commission fails to issue an Approval Order by ___________ Purchaser, by notice to Seller delivered on or before ___________ may terminate this REPA, without any further financial or other obligation to Seller as a result of such termination; provided that, if Purchaser has not on or prior to __________, provided notice to Seller of a termination of this

REPA as a result of the failure to obtain the Approval Order, Purchaser shall be deemed to have waived its right to terminate for failure to achieve such condition precedent.

(B) Purchaser from time to time during the Term of this REPA may file with the Commission one or more Cost Recovery Requests. In the event that Purchaser files a Cost Recovery Request during the Term of this REPA, but despite commercially reasonable efforts, is unable to obtain a Cost Recovery Order within the Cost Recovery Approval Period, Purchaser by notice to Seller delivered on or prior to thirty (30) days after expiration of the Cost Recovery Approval Period, may terminate this REPA, without any further financial or other obligation to Seller as a result of such termination; provided that, Purchaser shall remain liable to Seller for any amounts due under this REPA prior to the delivery of the notice of termination. Purchaser and Seller further agree that Purchaser may file more than one Cost Recovery Request during the Term of this REPA and that Purchaser's right to terminate this REPA in the event Purchaser fails to receive a Cost Recovery Order within the Cost Recovery Approval Period shall attach to each such Cost Recovery Request.

ARTICLE 7
SALE AND PURCHASE OF RENEWABLE ENERGY

7.1 Sale and Purchase.

Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to Purchaser, and Purchaser shall purchase and pay for, at the Contract Rate, all Renewable Energy generated by the Facility. [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

7.3 Title and Risk of Loss.

As between the Parties, Seller shall be deemed to be in control of the Renewable Energy output from the Facility up to the Point of Delivery, and Purchaser shall be deemed to be in control of such Renewable Energy output from and after the Point of Delivery. Title and risk of loss related to the Renewable Energy delivered by Seller to Purchaser hereunder shall transfer from Seller to Purchaser at the Point of Delivery. Title and risk of loss of the Renewable Energy Certificates and any Comparable Renewable Energy Certificates shall pass from Seller to Purchaser as provided in the rules governing GATS.

7.4 Curtailments.

(A) Seller shall at all times during the Term comply with the directives of the Transmission Operator, the Transmission Provider and the Interconnection Provider given pursuant to the Interconnection Agreement. In addition, Purchaser shall have the right to notify Seller, by telephonic communication or other method as reasonably determined by Purchaser, of a Reliability Curtailment directed by the Transmission Operator, the Transmission Provider or the Interconnection Provider or of an Economic Curtailment. In all cases of Reliability Curtailment, Seller shall reduce the net Energy delivered by the Facility at the Point of Delivery to the level directed by the Transmission Operator, the Transmission Provider or the Interconnection Provider, as applicable. If Purchaser receives any such directive of Reliability Curtailment, Purchaser shall promptly notify Seller of the maximum amount of Renewable Energy, if any, during such Reliability Curtailment that Seller may continue to deliver and Seller shall ensure that the amount of net Energy delivered by the Facility at the Point of Delivery does not exceed such amount. Except as provided in Section 7.1, no compensation shall be due from Purchaser to Seller as a result of any curtailment of the Facility's generation arising from any Reliability Curtailment directed by the Transmission Operator, the Transmission Provider or the Interconnection Provider. Any Economic Curtailment by Purchaser shall be of the entire Facility Capacity or portion thereof not less than minimum operational limit. Purchaser shall pay Seller the Economic Curtailment

Reimbursement Amount for the Economic Curtailment Energy during periods of Economic Curtailment and the Economic Curtailment Reimbursement Amount will be Seller's sole compensation from Purchaser as a result of Economic Curtailment.

(B) Purchaser shall be entitled to declare an Economic Curtailment by notice to Seller at any time during the Delivery Period. With respect to each such Curtailment:

(1) Purchaser shall promptly notify Seller, by telephonic communication or other method as reasonably determined by Purchaser, of the beginning and end Clock Hours of the Economic Curtailment.

(2) Upon receipt of such notice, Seller has the option, in its sole discretion, of (A) fully reducing or ceasing deliveries of Renewable Energy from the Facility pursuant to the Purchaser's instruction, or (B) not reducing or ceasing (or only partially reducing or ceasing) deliveries from the Facility as provided in the Purchaser's instruction, and selling the excess Renewable Energy so delivered to one or more third parties in accordance with Good Utility Practices. If Seller selects option (A), Purchaser shall pay Seller the Economic Curtailment Reimbursement Amount for the resulting Economic Curtailment Energy. If Seller selects option (B), Seller shall promptly notify Purchaser of such selection, Purchaser shall pay Seller the Economic Sold Curtailment Reimbursement Amount for the resulting Economic Sold Curtailment Energy and, if applicable, the Economic Curtailment Reimbursement Amount for any resulting Economic Curtailment Energy. Purchaser shall be entitled to all RECs associated with such Economic Sold Curtailment Energy.

(3) With respect to any Economic Curtailment occurring in any month, the invoice provided for such month by Seller pursuant to Section 9.1 of this REPA shall include a statement showing Seller's computation of (i) the Economic Curtailment Energy, (ii) the Economic Curtailment Reimbursement Amount, (iii) the Economic Sold Curtailment Energy and (iv) the Economic Sold Curtailment Reimbursement Amount, in each case to the extent applicable to such Economic Curtailment.

(4) Each Party agrees and acknowledges that (i) the damages that Seller may incur as a result of an Economic Curtailment by Seller would be difficult or impossible to predict with certainty and that the amounts contemplated by Section 7.4(B)(2) are a fair and reasonable calculation of such damages, and (iii) the required payment by Purchaser pursuant to such Section 7.4(B)(2) shall be Seller's sole remedy for such curtailment. An Economic Curtailment shall not be an Event of Default.

7.5 Renewable Energy Incentives.

(A) If, for any reason, Seller does not receive the Renewable Energy Incentives for any period, the cost of Renewable Energy Products delivered to Purchaser under this REPA shall not be affected, and the risk of not obtaining the Renewable Energy Incentives shall be borne solely by Seller.

(B) Seller shall be entitled to all Renewable Energy Incentives, and Purchaser acknowledges that Seller has the right to sell or transfer the Renewable Energy Incentives, at any rate and upon any terms and conditions that Seller may determine in its sole discretion without liability to Purchaser hereunder. Purchaser shall have no claim, right or interest in such Renewable Energy Incentives or in any amount that Seller realized from the sale of such incentives.

ARTICLE 8
PAYMENT CALCULATIONS

8.1 Payments at Contract Rate. Commencing on the first day of the Delivery Period, Purchaser shall pay Seller for the Renewable Energy delivered to Purchaser by Seller to the Point of Delivery and for other Renewable Energy Products associated therewith at the Contract Rate set forth in Exhibit C.

8.2 No Payment Obligation. For avoidance of doubt, Purchaser shall not be obligated to make any payment to Seller under Section 8.1 for any Energy which, regardless of reason or event of Force Majeure affecting either Party, (i) does not qualify as Renewable Energy, (ii) is not measured by the Electric Metering Device(s) installed pursuant to Section 5.4, as such measurement may be adjusted pursuant to Section 5.5, or (iii) is delivered to Purchaser at a location other than the Point of Delivery.

ARTICLE 9
BILLING AND PAYMENT

9.1 Billing Invoices.

The monthly billing period shall be the calendar month. No later than ten (10) Business Days after the end of each calendar month, Seller shall provide to Purchaser, by first-class mail or electronically, an invoice for the amount due Seller by Purchaser for the services provided by Seller and purchased by Purchaser, under this REPA, during the previous calendar month billing period. Seller's invoice will show all billing parameters, Contract Rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to Seller. Seller's failure to timely provide Purchaser with the monthly invoice shall not waive Purchaser's responsibility for payment under the terms stated in Section 9.2 below, except as provided in Section 13.9(B).

9.2 Payments.

Unless otherwise specified herein, payments due under this REPA shall be due and payable on or before the later of (i) the twentieth (20th) Day of the month following the month to which such payment relates and (ii) the tenth (10th) Business Day following receipt of the billing invoice. Unless Seller directs Purchaser otherwise, all payments by Purchaser to Seller shall be made by electronic funds transfer. If the amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated using an annual interest rate equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such Day (or if not published on such Day on the most recent preceding Day on which published), plus two percent (2%). If the due date occurs on a Day that is not a Business Day, the late payment charge shall begin to accrue on the next succeeding Business Day.

9.3 Billing Disputes.

Purchaser may dispute invoiced amounts on or prior to the second (2nd) anniversary of the issuance of the invoice related to such invoiced amounts, but shall pay to Seller the undisputed portion of invoiced amounts on or before the invoice due date. To resolve any billing dispute, the Parties shall use the procedures set forth in Section 13.9. When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount owed in accordance with the provisions of Section 9.2 from the date such amount was originally due. Purchaser and Seller at any time may offset against any and all amounts that may be due and owed to the other Party under this REPA any amounts that are owed by such other Party to Purchaser or Seller, as applicable, pursuant to this REPA including damages and other payments. Undisputed and non-offset portions of amounts invoiced under this REPA shall be paid on or before the due date or shall be subject to the late payment interest charges set forth in Section 9.2.

ARTICLE 10
OPERATIONS AND MAINTENANCE

10.1 Facility Operation.

Seller shall staff, control, and operate the Facility consistent at all times with Good Utility Practice(s) and the Contract Administration Procedures developed pursuant to Section 10.3. Personnel capable of starting, operating, and stopping the Facility shall be available, either at the Facility or capable of remotely starting, operating and stopping the Facility within ten (10) minutes' notice. In all cases, personnel capable of starting, operating, and stopping the Facility shall be continuously reachable by phone or pager. Seller shall maintain the Communications Equipment in good operating order at all times during the Term.

10.2 Outage and Performance Reporting.

(A) Seller shall comply with all NERC, RFC and the Transmission Operator generating unit outage and performance reporting requirements, as they may be revised from time to time, and as they apply to the Facility.

(B) When Forced Outages of twenty percent (20%) or greater of the Facility occur, Seller shall notify Purchaser of the existence, nature, and expected duration of the Forced Outage as soon as practical, but in no event later than (i) thirty (30) minutes after the Forced Outage occurs if it occurs during normal business hours or (ii) the beginning of normal business hours if such Forced Outage occurs outside of normal business hours. Seller shall thereafter inform Purchaser of changes in the expected duration of the Forced Outage unless relieved of this obligation by Purchaser for the duration of each Forced Outage.

(C) Seller shall provide Purchaser with prompt notice of any malfunction or other failure of the Communications Equipment.

10.3 Contract Administration Committee and Contract Administration Procedures.

(A) Purchaser and Seller shall each appoint one representative and one alternate representative to act in matters relating to the Parties' performance obligations under this REPA and to develop operating arrangements for the generation, delivery and receipt of Renewable Energy hereunder. Such representatives shall constitute the Contract Administration Committee, and shall be as specified on Exhibit D. The Parties shall notify each other in writing of such appointments and any changes thereto. The Contract Administration Committee shall have no authority to modify the terms or conditions of this REPA.

(B) Prior to the Commercial Operation Date, the Contract Administration Committee shall develop mutually agreeable written Contract Administration Procedures which shall include, but not be limited to, method of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list for applicable Purchaser and Seller operating centers; operations and maintenance scheduling and reporting; Renewable Energy reports; unit operations log; and such other matters as may be mutually agreed upon by the Parties.

10.4 Access to Facility.

Appropriate representatives of Purchaser shall at all reasonable times, including weekends and nights, and with reasonable prior notice, have access to the Facility to read meters, to perform maintenance and service of Purchaser's equipment and to perform all inspections and operational reviews as may be reasonably appropriate to facilitate the performance of this REPA; provided that Purchaser does not interfere in any material respect with the operation of the Facility, and causes all persons visiting the Facility on its behalf to comply with all of Seller's applicable safety, health and similar rules and requirements.

10.5 Reliability Standards.

Seller shall operate the Facility in a manner that complies in all material respects with all national and regional reliability standards, including standards set by the Transmission Operator, RFC, NERC and the FERC, or any successor agencies setting reliability standards for the operation of generation facilities. To the extent that Seller does not operate the Facility in accordance with such standards that result in monetary penalties being assessed to Purchaser by the Transmission Operator, RFC, NERC, or the FERC, Seller shall reimburse Purchaser for its share of such monetary penalties.

10.6 Beneficial Environmental Interests.

The Parties acknowledge that future or existing legislation or regulation may create value in the ownership, use or allocation of the Beneficial Environmental Interests of the Facility. Purchaser shall own or be entitled to claim all Beneficial Environmental Interests to the extent they may exist during the Term.

10.7 Availability Forecast.

(A) On or prior to the tenth Business Day of each month commencing after the Commercial Operation Date, Seller will furnish Purchaser with a notice setting forth its good faith estimate of (i) the hourly availabilities of the Facility for such month and the next month and (ii) the expected average daily availability of the Facility for each of the ten (10) months subsequent to such next month. With respect to the preceding clause (A)(i), if Seller later updates its availability estimates for such periods, it shall deliver to Purchaser a revised notice setting forth its then current good faith estimate of hourly availabilities of the Facility for the balance of such month and for the next month. Seller does not guarantee the accuracy of said notices and said notices are only intended to be its good faith estimate of the projected availability of the Facility at the time such notice is given.

(B) (B)Seller shall furnish to Purchaser a notice substantially in the form attached hereto as Exhibit K (an "Availability Notice") at or before 9:00 a.m. EPT on the Business Day immediately prior to the first Day to which such Availability Notice shall relate that shall set forth the Facility Capacity that Seller anticipates will actually be available in each hour through the next Business Day and each subsequent Business Day to which such Availability Notice relates. Seller also shall furnish to Purchaser a revised Availability Notice promptly after the occurrence of any Force Majeure event, Forced Outage, unscheduled outage or other unplanned maintenance, derating, or other event that would reduce or interrupt Renewable Energy or Ancillary Services associated with the Facility Capacity or cause the controlling Availability Notice to be inaccurate or incomplete in any material respect, with a description of the circumstances thereof. Each such Availability Notice shall be effective until delivery of a subsequent Availability Notice. Seller does not guarantee the accuracy of said Availability Notices, and said Availability Notices are only intended to be its good faith estimate of the projected availability of the Facility at the time such notice is given.

10.8 Planned Maintenance Schedule.

No later than (a) the Commercial Operation Date and (b) two months prior to each calendar year thereafter during the Term, Seller shall submit to Purchaser a schedule of planned maintenance for the following calendar year for the Facility, which schedule shall be updated by Seller by each March 31 and September 30 thereafter to cover the twelve month period following each such update. Such schedule shall be consistent with the requirements of Good Utility Practice and the Interconnection Agreement, and otherwise in accordance with this REPA. No planned maintenance of the Facility substation or any other portion of the Facility that would affect the availability of more than 10% of the Facility Capacity at any one time may be scheduled during the months of January, February, June, July, August or December during the Delivery Period; provided, however, that planned maintenance may be scheduled during such period to the extent (i) required by or necessary to preserve any equipment warranties or (ii) the failure to perform such planned maintenance is contrary to operation in accordance with Good Utility Practice(s). Such schedule, and each supplement thereto, shall indicate the planned commencement and completion dates for each planned maintenance during the period covered thereby, as well as the affected portion(s) of the Facility. If Purchaser desires to change the scheduled commencement or duration of planned maintenance, the Purchaser shall notify the Seller of the requested change and the Seller shall use reasonable efforts to accommodate the requested change. At least one (1) week prior to any planned maintenance, Seller shall notify Purchaser via e-mail or telephonically of the expected commencement date of such planned maintenance, the affected portion(s) of the Facility during such planned maintenance and the expected completion date of such planned maintenance. As soon as practicable, all such telephonic notification shall be confirmed in writing.

10.9 REC Certification.

(A) Seller shall be responsible for causing the GATS Certificates delivered under this REPA to meet all requirements for entry into GATS and as otherwise specified by PJM-EIS. Seller shall be responsible for registering and maintaining compliance during the duration of this REPA with GATS and the PJM-EIS and will be responsible for timely delivery as allowed by GATS and PJM-EIS. The Parties will effectuate the delivery and receipt of the GATS certificates by making and conforming appropriate entries into GATS and otherwise as specified by the PJM-EIS.

(B) Seller shall, at its own cost, take all actions necessary to register for and maintain participation in any applicable system or program established by the federal Governmental Authority and the States of Kentucky, Ohio, Illinois, Maryland, Pennsylvania and West Virginia, along with any other State(s) reasonably designated by Purchaser, to monitor, track, certify or trade RECs. To the extent necessary, Seller shall assign to Purchaser all rights, title and authority for Purchaser to register, own, hold and manage certificates that represent RECs in Purchaser's own name and to Purchaser's account, including any rights associated with any such renewable energy information or tracking system that may be established with regard to monitoring, tracking, certifying, or trading such RECs. Upon the request of Purchaser from time to time, at no cost to Purchaser, (i) Seller shall deliver or cause to be delivered to Purchaser such attestations/certifications of RECs as may be required to comply with any such certification system or program, and (ii) Seller shall provide full cooperation in connection with Purchaser's registration and certification of RECs. Purchaser shall assist Seller with the matters described in this subsection (B) to the extent reasonably requested by Seller during the Term.

10.10 Public Statements/Other Use.

Without the written consent of Purchaser, Seller shall not (1) make any public statement or representation that is inconsistent with Purchaser's entitlement to the Renewable Energy Products (or any portion thereof), (2) use the Facility's Beneficial Environmental Interests to meet any federal, state or local renewable energy requirement, renewable energy procurement, renewable energy portfolio standard or other renewable energy mandate, or (3) advertise, market, sell, retire, convey or otherwise transfer or seek to transfer the Facility's Beneficial Environmental Interests, which rights are expressly reserved to Purchaser during the Term of this REPA.

10.11 Real-Time Information.

Purchaser will have the option to require that Seller provide real-time data to Purchaser consistent with Purchaser's real-time data procedures and processes. Should Purchaser exercise this option and request such real-time data, Seller will use commercially reasonable efforts on and after such date to continuously transmit real-time date to Purchaser in compliance with Purchaser's real-time data procedures and processes. Purchaser and Seller shall each bear the cost of and responsibilities for their respective systems, equipment and communications links required for delivery and receipt of such real-time information. In the event that Seller fails to continuously transmit real-time data to Purchaser, and such real-time data transmission has not been restored within 2 Business Days after Purchaser notifies Seller of the failure thereof, Seller shall be responsible for all imbalance costs, operating reserves, and congestion costs under Section 5.6(C) and (D) until such time as the transmission of real-time data has been restored.

10.12 Web-Based Operational Reporting.

Purchaser may at its option make available to Seller on the Internet a web-based reporting system which will provide the Parties with the capability to generate and submit standardized reports for purposes of satisfying the requirements of the Parties contained in Sections 10.2, 10.7 and 10.8. Purchaser will develop user requirements for such reporting system in consultation with Seller.

ARTICLE 11
SECURITY FOR PERFORMANCE

11.1 Seller Security Fund.

(A) Seller shall establish the Security Fund at the initial amount of [redacted] Seller shall thereafter maintain the Security Fund, if necessary, at such level throughout the Term; provided that if this REPA is terminated by Purchaser pursuant to Section 6.1, Purchaser shall release the Security Fund to Seller within ten (10) Business Days of such termination.

(B) In addition to any other remedy available to it, Purchaser may, before or after termination of this REPA and so long as the Security Fund is required to be outstanding after termination of this REPA pursuant to Section 11.1(F), draw from the Security Fund. Purchaser may, in its sole discretion, draw all or any part of such amounts due to it from any form of Security Fund, and from all such forms, and in any sequence Purchaser may select. Any failure to draw upon the Security Fund or other security for any damages or other amounts due to Purchaser shall not prejudice Purchaser's rights to recover such damages or amounts in any other manner.

(C) The Security Fund shall be maintained at Seller's expense, shall be issued by or deposited in an Issuer (as applicable), and shall be in the form of one or more of the following instruments. Seller may replace the form of the Security Fund at any time and from time to time upon reasonable prior notice to Purchaser, but the Security Fund must at all times be comprised of one or any combination of the following:

(1) An irrevocable standby letter of credit in substantially the form of Exhibit L from an Issuer that is a Creditworthy Bank. Such security must be issued for a minimum term of three hundred and sixty (360) Days. Seller shall cause the renewal or extension of the security for additional consecutive terms of three hundred and sixty (360) Days or more (or, if shorter, the remainder of the period described in Section 11.1(F)) no later than thirty (30) Days prior to each expiration date of the security. If the security is not renewed or extended as required herein (such condition, the "Failure to Extend Condition"), Purchaser shall have the right to draw immediately upon the letter of credit and be entitled to hold the amounts so drawn as security, provided Purchaser satisfies the conditions of Section 11.1(C)(2)(i). If Purchaser does not meet the conditions of Section 11.1(C)(2)(i), Purchaser will place the amounts so drawn in an interest bearing account or escrow in accordance with Section 11.1(C)(2)(ii), until and unless Seller provides a substitute form of such security meeting the requirements of this Section 11.1. Such amounts shall constitute part of the Security Fund pursuant to Section 11.1(C)(2) for all purposes of this REPA (including for the return of such Cash to Seller according to Section 11.1(F)).

(2) United States currency ("Cash") deposited with (i) Purchaser, provided that Purchaser satisfies the following conditions: (a) it is not a defaulting Party and (b) Purchaser is a Creditworthy Entity. In such event, Purchaser will pay interest to Seller on Cash held at the Federal Funds Effective Rate and may draw on the Cash only in the circumstances, and in the amounts, that a letter of credit in the form of Exhibit L could be drawn (except that the Failure to Extend Condition or Failure to Replace Condition shall not apply as a valid reason for disbursement); or (ii) if, and only if, Purchaser does not meet the aforementioned conditions of Section 11.1(C)(2)(i), then the Cash shall be held with an Issuer that is a Creditworthy Bank, either: (a) in an account under which Purchaser is designated as beneficiary with sole authority to draft from the account or otherwise access the security only in the circumstances, and in the amounts, that a letter of credit in the form of Exhibit L could be drawn (except that the Failure to Extend Condition or Failure to Replace Condition shall not apply as a valid reason for disbursement); or (b) held by Issuer as escrow agent with instructions to pay claims made by Purchaser pursuant to this REPA, such instructions to allow drawing by

Purchaser only in the circumstances, and in the amounts, that a letter of credit in the form of Exhibit L could be drawn (except that the Failure to Extend Condition or Failure to Replace Condition shall not apply as a valid reason for disbursement). Security held pursuant to Section 11.1(C)(2)(ii) shall be subject to the following: (x) include a requirement for prompt notice to Purchaser from Seller in the event that the sums held as security in the account or escrow do not at any time meet the required level for the Security Fund as set forth in this Section 11.1 and (y) funds held in the account or escrow may be deposited in a money-market fund, short-term treasury obligations, investment-grade commercial paper and other liquid investment-grade investments with maturities of three months or less, with all investment income thereon to be taxable to, and to accrue for the benefit of, Seller. Seller grants to Purchaser a present and continuing first priority security interest in all Cash which has been transferred to Purchaser or held by Issuer. At such times as the balance of Cash held by Purchaser or by Issuer exceeds the amount of Seller's obligation to provide security hereunder, Purchaser shall remit to Seller on demand any excess in the account above Seller's obligations.

(3) A guaranty in substantially the form of Exhibit M from an Issuer that is a Creditworthy Entity.

(D) If the Issuer of any Security Fund instrument ceases to be a Creditworthy Bank (in the case of a letter of credit Issuer or holder of Cash) or a Creditworthy Entity (in the case of an Issuer of a payment guaranty) or any Security Fund instrument ceases to be in full force and effect, then Seller shall be required to replace the affected Security Fund instrument with another Security Fund instrument meeting the criteria set forth in Section 11.1(C) no later than ten (10) Days after receiving notice from Purchaser that such replacement of the Security Fund instrument is required pursuant to this Section 11.1(D). If the Security Fund instrument is a letter of credit and is not replaced as required herein (such condition, the "Failure to Replace Condition"), Purchaser shall have the right to draw immediately upon the letter of credit and be entitled to hold the amounts so drawn as security, provided Purchaser satisfies the conditions of Section 11.1(C)(2)(i). If Purchaser does not meet the conditions of Section 11.1(C)(2)(i), Purchaser will place the amounts so drawn, in an interest bearing account or escrow in accordance with Section 11.1(C)(2)(ii), until and unless Seller provides a substitute form of such security meeting the requirements of this Section 11.1. Such amounts shall constitute part of the security pursuant to Section 11.1(C)(2) for all purposes of this REPA (including for the return of such Cash to Seller according to Section 11.1(F)).

(E) If any Security Fund instrument is replaced in accordance with Section 11.1(C) or 11.1(D), (i) if the Security Fund instrument replaced is Cash, Purchaser shall immediately return the Cash (including any interest earned thereon) to Seller, or (ii) if the Security Fund instrument being replaced is not Cash, the Issuer shall be deemed released from all obligations under such replaced Security Fund instrument, and Purchaser shall execute any documents reasonably requested by Seller or the Issuer thereof to confirm such release.

(F) On the later of (i) one hundred eighty (180) days after the termination or expiration of this REPA or (ii) the resolution of all then-pending disputes under this REPA, (a) if Cash is part of the Security Fund, Purchaser shall immediately return to Seller such Cash (together with any interest earned thereon), and (b) if a guaranty or letter of credit is part of the Security Fund, the Issuer(s) that provided or issued such Security Fund instrument shall be deemed released from all obligations under such Security Fund instrument, and Purchaser shall execute any documents reasonably requested by Seller or the Issuer thereof to confirm such release.

ARTICLE 12
DEFAULT AND REMEDIES

12.1 Events of Default of Seller.

(A) Any of the following shall constitute an "Event of Default" of Seller upon its occurrence and no cure period shall be applicable:

(1) Seller's dissolution or liquidation;

(2) Seller's assignment of this REPA or any of its rights hereunder for the benefit of creditors (except for an assignment to the Facility Financing Representative as security under the Financing Documents as permitted by this REPA);

(3) Seller's voluntary filing of a petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency act of any state, or Seller voluntarily taking advantage of any such law or act by answer or otherwise;

(4) The filing of a case in bankruptcy or any proceeding under any other insolvency law against Seller or the Issuer providing a guaranty pursuant to Section 11(C)(3) hereof as debtor, and such case or proceeding has not been dismissed within sixty (60) Days; or

(5) The sale by Seller to a third party, or diversion by Seller for any use, of Renewable Energy Products committed to Purchaser by Seller, except to the extent permitted by this REPA.

(B) Seller's failure to comply with its obligations under Section 11.1 shall constitute an Event of Default of Seller if not cured within five (5) Business Days after the date of written notice from Purchaser to Seller and the Facility Financing Representative as provided for in Section 13.1;

(C) Seller's failure to make any payment required under this REPA (net of any other rights of offset that Seller may have pursuant to Section 9.3), shall constitute an Event of Default of Seller if not cured within ten (10) Days after the date of written notice from Purchaser to Seller and the Facility Financing Representative as provided for in Section 13.1:

(D) Any of the following shall constitute an Event of Default of Seller if not cured within thirty (30) Days after the date of written notice from Purchaser to Seller and the Facility Financing Representative as provided for in Section 13.1:

(1) Abandonment;

(2) Seller's failure to maintain in effect any material agreements required to deliver the Renewable Energy committed to Purchaser hereunder to the Point of Delivery pursuant to Section 5.3, including the Interconnection Agreement;

(3) Seller's failure to comply with any material obligation under this REPA, other than as expressly specified in this Article 12, which would result in a material adverse impact on Purchaser;

(4) Seller's assignment of this REPA, or Seller's sale or transfer of its interest, or any part thereof, in the Facility, except as permitted in accordance with Article 19; or

(5) Any representation or warranty made by Seller in this REPA shall prove to have been false in any material respect when made, except to the extent expressly limited to the time when made, if such cessation would reasonably be expected to result in a material adverse impact on Purchaser.

(E) Seller's failure to meet the Commercial Operation Milestone shall constitute an Event of Default of Seller if not cured within [redacted] after the date of written notice from Purchaser to Seller and the Facility Financing Representative as provided for in Section 13.1; [redacted] Delay Liquidated Damages under Section 4.10 shall continue accruing until the occurrence of one of the following events: (i) the Commercial Operation Date is achieved, or (ii) this REPA is terminated.

[redacted]

[redacted]

12.2 Facility Financiers' Right to Cure Default of Seller.

Seller shall provide Purchaser with a notice identifying the Facility Financing Representative and the Parties shall use commercially reasonable efforts to enter into a Consent and Agreement in substantially the form of Exhibit N attached hereto with such Facility Financing Representative. Following execution of a Consent and Agreement, Purchaser shall provide notice of any default of Seller under Section 12.1 to the Facility Financing Representative, and Purchaser will accept a cure to such Default of Seller performed by the Facility Financing Representative, in accordance with the terms of the applicable Consent and Agreement.

12.3 Events of Default of Purchaser.

(A) Any of the following shall constitute an "Event of Default" of Purchaser upon its occurrence and no cure period shall be applicable:

(1) Purchaser's dissolution or liquidation;

(2) Purchaser's assignment of any of its rights hereunder for the benefit of creditors;

(3) Purchaser's voluntary filing of a petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency act of any State, or Purchaser voluntarily taking advantage of any such law or act by answer or otherwise;

(4) The filing of a case in bankruptcy or any proceeding under any other insolvency law against Purchaser and such case or proceeding is not dismissed within sixty (60) Days; or

(5) Purchaser's assignment of this REPA, except as permitted in accordance with Article 19.

(B) Purchaser's failure to make any payment due hereunder (net of outstanding damages and any other rights of offset that Purchaser may have pursuant to this REPA) shall constitute an Event of Default of Purchaser if not cured within ten (10) Days after the date of written notice from Seller to Purchaser as provided for in Section 13.1.

(C) Purchaser's failure to comply with any material obligation under this REPA, other than as otherwise expressly specified in this Article 12, which would result in a material adverse impact on Seller, shall constitute an Event of Default of Purchaser if not cured within thirty (30) Days after the date of written notice from Seller to Purchaser as provided for in Section 13.1.

(D) Any representation or warranty made by Purchaser in this REPA shall prove to have been false in any material respect when made, except to the extent expressly limited to the time when made, or ceases to remain true during the Term if such cessation would reasonably be expected to result in a material adverse impact on Seller, and shall constitute an Event of Default of Purchaser if not cured within thirty (30) Days after the date of written notice from Seller to Purchaser as provided for in Section 13.1.

12.4 Damages Prior to Termination.

For all breaches or Events of Default (other than those in respect of any delay of the Commercial Operation Date and any Output Shortfall, for which Sections 4.10 and 7.2 of REPA provide a remedy that is stated to be an exclusive remedy of Purchaser), the non-breaching or non-defaulting Party shall be entitled to receive from the breaching or defaulting Party its actual, direct damages resulting from such breach or Event of Default.

12.5 Termination.

Upon the occurrence of an Event of Default which has not been cured within the applicable cure period and is continuing, the non-defaulting Party shall have the right to declare, by giving notice to the defaulting Party (and, if the defaulting Party is Seller, to the Facility Financing Representative), a date no less than one (1) Day and no more than thirty (30) Days after the date of such notice upon which this REPA shall terminate. Neither Party shall have the right to terminate this REPA except as provided for upon the occurrence of an Event of Default as described above or as otherwise may be explicitly provided for in this REPA. Except in the event of termination by Purchaser in the case of the Event of Default of Seller in Section 12.1(E), the non-defaulting Party shall be entitled to receive from the defaulting Party, all of the actual damages incurred by the non-defaulting Party as a result of such termination, including the Total Replacement Energy Costs or Resale Costs (if any) incurred by the non-defaulting Party as a result of the termination of this REPA. In the event of termination by Purchaser in the case of the Event of Default of Seller in Section 12.1(E), neither Party shall have any liability arising out of such termination, without prejudice to Seller's obligation to pay Delay Liquidated Damages in respect of the period prior to such termination.

12.6 Specific Performance.

In addition to the other remedies specified in this Article 12, in the event that any breach of this REPA by a Party is not cured within the applicable cure period set forth herein, the other Party shall have the right to specific performance.

12.7 Remedies Cumulative.

Subject to the exclusivity of Delay Liquidated Damages provided in Section 4.10, the Output Shortfall Liquidated Damages and Capacity Shortfall Liquidated Damages provided in Section 7.2 and the limitations on damages set forth in Sections 12.4 and 12.8, each right or remedy of the Parties provided for in this REPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this REPA, at law or in equity, and the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.8 Waiver and Exclusion of Other Damages.

The Parties confirm that the express remedies and measures of damages provided in this REPA satisfy the essential purposes hereof. If no remedy or measure of damages is expressly herein provided, the obligor's liability shall be limited to direct, actual damages only. NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY, SPECIAL OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES BY STATUTE, IN TORT OR CONTRACT (EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN); PROVIDED, THAT IF EITHER PARTY IS HELD LIABLE TO A THIRD PARTY FOR SUCH DAMAGES AND THE PARTY HELD LIABLE FOR SUCH DAMAGES IS ENTITLED TO INDEMNIFICATION THEREFORE FROM THE OTHER PARTY HERETO, THE INDEMNIFYING PARTY SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE THE INDEMNIFIED PARTY FOR, SUCH DAMAGES. To the extent any damages required to be paid hereunder are liquidated, the Parties acknowledge that the damages are difficult or impossible to determine, that otherwise obtaining an adequate remedy is inconvenient, and that the liquidated damages constitute a reasonable approximation of the harm or loss.

12.9 Payment of Damages.

Without limiting any other provisions of this Article 12 and at any time before or after termination of this REPA, the non-defaulting Party may send the other Party an invoice for such damages (including, if applicable, Delay Liquidated Damages, Output Shortfall Liquidated Damages and Capacity Shortfall Liquidated Damages) or other amounts as are due to the non-defaulting Party at such time from the defaulting Party under this REPA and such invoice shall be payable in the manner, and in accordance with the applicable provisions, set forth in Article 9, including the provision for late payment charges. In the case of damages owed by Seller to Purchaser, Purchaser may, subject to the provisions of Section 11.1, withdraw funds from the Security Fund, as needed to provide payment for such invoice if the invoice is not paid by Seller on or before the tenth (10th) Business Day following the invoice due date.

12.10 Duty to Mitigate.

Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of the REPA.

ARTICLE 13
CONTRACT ADMINISTRATION AND NOTICES

13.1 Notices in Writing.

Notices required by this REPA shall be addressed to the other Party, including the other Party's representative on the Contract Administration Committee, at the addresses noted in Exhibit D as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this REPA to be given by one Party to the other Party shall be in writing. It shall either be hand delivered or mailed, postage prepaid, to the representative of said other Party. If mailed, the notice, request, consent or other communication shall be simultaneously sent by facsimile or other electronic means. Any such notice, request, consent, or other communication shall be deemed to have been received by the Close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close in which case it shall be deemed received at the close of the next Business Day). Real-time or routine communications concerning Facility operations shall be exempt from this Section.

13.2 Representative for Notices.

Each Party shall maintain a designated representative to receive notices. Such representative may, at the option of each Party, be the same person as that Party's representative or alternate representative on the Contract Administration Committee, or a different person. Either Party may, by written notice to the other Party, change the representative or the address to which such notices and communications are to be sent.

13.3 Authority of Representatives.

The Parties' representatives designated above shall have authority to act for its respective principals in all technical matters relating to performance of this REPA and to attempt to resolve disputes or potential disputes. However, they, in their capacity as representatives, shall not have the authority to amend or modify any provision of this REPA.

13.4 Operating Records.

Seller and Purchaser shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this REPA, including such records as may be required by state or federal regulatory authorities and the Transmission Operator in the prescribed format.

13.5 Operating Log.

Seller shall maintain an accurate and up-to-date operating log, in electronic format, at the Facility with records of production for each Clock Hour; changes in operating status; Scheduled Outages/Deratings and Forced Outages for the purposes of proper administration of this REPA, including such records as may be required by state or federal regulatory authorities and the Transmission Operator in the prescribed format.

13.6 Billing and Payment Records.

To facilitate payment and verification, Seller and Purchaser shall keep all books and records necessary for billing and payments in accordance with the provisions of Article 9 and grant the other Party reasonable access to those records. All records of Seller pertaining to the operation of a Facility shall be maintained on the premises of the Facility or at the notice address listed in Exhibit D. For audit and verification purposes, Seller will grant Purchaser read-only access to the PJM eSuite accounts for the node associated with the PJM charges and credits for the Renewable Energy Products from the Facility Capacity.

13.7 Examination of Records.

Seller and Purchaser may examine the financial and Operating Records and data kept by the other Party relating to transactions under and administration of this REPA, at any time during the period the records are required to be maintained, upon request and during normal business hours.

13.8 Exhibits.

Either Party may change the information for their notice addresses in Exhibit D at any time upon written notice to but without the approval of the other Party. Exhibit C may only be changed in accordance with Section 20.4. Exhibit E may be changed in accordance with Section 16.2(B). All other Exhibits may only be modified by the mutual agreement of Seller and Purchaser.

13.9 Dispute Resolution.

(A) In the event of any dispute, controversy or claim arising out of or relating to this REPA (a "Dispute"), within ten (10) Days following the delivered date of a written request by either Party (a "Dispute Notice"), (i) each Party shall appoint a representative (individually, a "Party Representative", together, the "Parties' Representatives"), and (ii) the Parties' Representatives shall meet, negotiate and attempt in good faith to resolve the Dispute quickly, informally and inexpensively. In the event the Parties' Representatives have not resolved the Dispute within thirty (30) Days after commencement of negotiations, within ten (10) Days following any request by either Party at any time thereafter, each Party Representative (I) shall independently prepare a written summary of the Dispute describing the issues and claims, (II) shall exchange its summary with the summary of the Dispute prepared by the other Party Representative, and (III) shall submit a copy of both summaries to a senior officer of the Party Representative's Party with authority to irrevocably bind the Party to a resolution of the Dispute. Within ten (10) Business Days after receipt of the Dispute summaries, the senior officers for both Parties shall negotiate in good faith to resolve the Dispute. If the Parties have not resolved the Dispute within fourteen (14) Days following receipt of the Dispute summaries by the senior officers, either Party may seek available legal and equitable remedies.

(B) Notwithstanding any provision in this REPA to the contrary, if no Dispute Notice has been issued within twenty-four (24) months following the occurrence of all events and the existence of all circumstances giving rise to the Dispute (regardless of the knowledge or potential knowledge of either Party of such events and circumstances), the Dispute and all claims related thereto shall be deemed waived and the aggrieved Party shall thereafter be barred from proceeding thereon; provided, however, that the limitation set forth in this subsection (B) shall not apply to any Dispute Notices regarding claims for indemnification under this REPA for third party claims.

(C) Seller and Purchaser each hereby knowingly, voluntarily and intentionally waive any rights they may have to a trial by jury in respect of any litigation based hereon, or arising out of, under, or in connection with, this REPA or any course of conduct, course of dealing, statements (whether oral or written) or actions of Seller and Purchaser related hereto and expressly agree to have any disputes arising under or in connection with this REPA be adjudicated by a judge of the court having jurisdiction without a jury.

ARTICLE 14
FORCE MAJEURE

14.1 Definition of Force Majeure.

[redacted]

[redacted]

[redacted]

14.2 Applicability of Force Majeure.

(A) Other than as set forth in Section 14.3, neither Party shall be responsible or liable for any delay or failure in its performance under this REPA (other than the obligation to make payment of amounts due and payable under this REPA), nor shall any delay, failure, or other occurrence or event become an Event of Default, to the extent such delay, failure, occurrence or event is substantially caused by conditions or events of Force Majeure, provided that:

(1) the non-performing Party gives the other Party prompt written notice describing the particulars of the occurrence of the Force Majeure;

(2) the suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure;

(3) the non-performing Party proceeds with reasonable diligence to remedy its inability to perform and provides weekly progress reports to the other Party describing actions taken to end the Force Majeure; and

(4) when the non-performing Party is able to resume performance of its obligations under this REPA, that Party shall give the other Party prompt written notice to that effect.

(B) Except as otherwise expressly provided for in this REPA, the existence of a condition or event of Force Majeure shall not relieve the Parties of their obligations under this REPA (including payment obligations) to the extent that performance of such obligations is not precluded by the condition or event of Force Majeure.

14.3 Limitations on Effect of Force Majeure.

In no event will any delay or failure of performance caused by any conditions or events of Force Majeure extend this REPA beyond its stated Term. In the event that any delay or failure of performance caused by conditions or events of Force Majeure prevents the performance of a Party's obligations hereunder in any material respect and continues for an uninterrupted period of three hundred sixty-five (365) Days from its occurrence or inception, as noticed pursuant to Section 14.2(A), the Party not claiming Force Majeure may, at any time following the end of such three hundred sixty-five (365) Day period, terminate this REPA upon written notice to the affected Party, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination. The Party not claiming Force Majeure may, but shall not be obligated to, extend such three hundred sixty-five (365) Day period, for such additional time as it, at its sole discretion, deems appropriate, if the affected Party is exercising due diligence in its efforts to cure the conditions or events of Force Majeure.

ARTICLE 15
REPRESENTATIONS, WARRANTIES AND COVENANTS

15.1 Seller's Representations, Warranties and Covenants.

Seller hereby represents and warrants as follows:

(A) Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the State of Kentucky. Seller is qualified to do business in each other jurisdiction where the failure to so qualify would have a material adverse effect on the business or financial condition of Seller; and Seller has all requisite power and authority to conduct its business, to own its assets, and to execute, deliver, and perform its obligations under this REPA.

(B) The execution, delivery, and performance of its obligations under this REPA by Seller have been duly authorized by all necessary limited liability company action, and do not and will not:

(1) require any consent or approval by any governing body of Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Purchaser upon its request);

(2) violate any provision of law, rule, regulation, order, writ, judgment, injunction, decree, determination, or award currently in effect having applicability to Seller or violate any provision in any formation documents of Seller, the violation of

which could have a material adverse effect on the ability of Seller to perform its obligations under this REPA;

(3) result in a breach or constitute a default under Seller's formation documents or bylaws, or under any agreement relating to the management or affairs of Seller or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Seller is a party or by which Seller or its assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Seller to perform its obligations under this REPA; or

(4) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this REPA) upon or with respect to any of the assets of Seller now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Seller to perform its obligations under this REPA.

(C) This REPA is a valid and binding obligation of Seller.

(D) The execution and performance of this REPA will not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party or any judgment, order, statute, or regulation that is applicable to Seller or the Facility.

(E) To the best knowledge of Seller, and except for those permits, consents, approvals, licenses and authorizations identified in Exhibit F, or those which Seller anticipates will be obtained by Seller in the ordinary course of business, all permits, consents, approvals, licenses, authorizations, or other action required by any Governmental Authority to authorize Seller's execution, delivery and performance of this REPA have been duly obtained and are in full force and effect.

(F) Seller shall comply with all applicable local, state, and federal laws, regulations, and ordinances, including applicable equal opportunity and affirmative action requirements and all applicable federal, state, and local environmental laws and regulations presently in effect or which may be enacted during the Term of this REPA.

(G) Seller shall disclose to Purchaser, the extent of, and as soon as it is known to Seller, any violation of any environmental laws or regulations arising out of the construction or operation of the Facility, or the presence of Environmental Contamination at the Facility or on the Site, alleged to exist by any Governmental Authority having jurisdiction over the Site, or the existence of any past or present enforcement, legal, or regulatory action or proceeding relating to such alleged violation or alleged presence of Environmental Contamination.

15.2 <u>Purchaser's Representations, Warranties and Covenants</u>.

Purchaser hereby represents and warrants as follows:

(A) Purchaser is a corporation duly organized, validly existing and in good standing under the laws of the State of Kentucky and is qualified to do business in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of Purchaser; and Purchaser has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this REPA.

(B) The execution, delivery, and performance of its obligations under this REPA by Purchaser have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval of Purchaser's Board of Directors, or shareholders, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Seller upon its request);

(2) violate any provision of law, rule, regulation, order, writ, judgment, injunction, decree, determination, or award currently in effect having applicability to Purchaser or violate any provision in any corporate documents of Purchaser, the violation of which could have a material adverse effect on the ability of Purchaser to perform its obligations under this REPA;

(3) result in a breach or constitute a default under Purchaser's corporate charter or bylaws, or under any agreement relating to the management or affairs of Purchaser, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Purchaser is a party or by which Purchaser or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Purchaser to perform its obligations under this REPA; or

(4) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this REPA) upon or with respect to any of the assets or properties of Purchaser now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Purchaser to perform its obligations under this REPA.

(C) This REPA is a valid and binding obligation of Purchaser.

(D) The execution and performance of this REPA will not conflict with or constitute a breach or default under any contract or agreement of any kind to which Purchaser is a party or any judgment, order, statute, or regulation that is applicable to Purchaser.

(E) To the best knowledge of Purchaser, and except for the conditions precedent described in Section 6.1, all approvals, authorizations, consents, or other action required by any Governmental Authority to authorize Purchaser's execution, delivery and performance of this REPA, have been duly obtained and are in full force and effect.

ARTICLE 16
INSURANCE

16.1 Evidence of Insurance.

Seller shall, promptly upon renewal of insurance each calendar year or partial calendar year during the Term, provide Purchaser, at the insurance address listed in Exhibit D, with a copy of insurance certificates acceptable to Purchaser evidencing that insurance coverages for the Facility are in compliance with the specifications for insurance coverage set forth in Exhibit E to this REPA. Such certificates shall (a) name Purchaser as an additional insured (except workers' compensation); (b) provide a waiver of any rights of subrogation against Purchaser, its Affiliates and their officers, directors, agents, subcontractors, and employees; and (c) indicate that the Commercial General Liability policy has been endorsed as described above. Seller shall use commercially reasonable efforts to procure that the insurance policies required by this REPA provide that Purchaser shall receive thirty (30) Days prior written notice of non-renewal, cancellation of, or significant modification to any of the corresponding policies (except that such notice shall be ten (10) Days for non-payment of premiums); provided, however, that, if Seller is unable to require its insurers to provide such notices to Purchaser, Seller shall provide Purchaser, at the insurance address listed in Exhibit D; with any such notice of non-renewal or cancellation to any corresponding policy which Seller receives from any of its insurers as soon as practicable following Seller's receipt of such notice but in no event later than five (5) Business Days following Seller's receipt, if any, of the relevant notice. All policies shall be written with insurers that Purchaser, in its reasonable discretion, deems acceptable (such acceptance will not be unreasonably withheld, conditioned or delayed). All policies shall contain an endorsement that Seller's policy shall be primary in all instances regardless of like coverages, if any, carried by Purchaser. Seller's liability under this REPA is not limited to the amount of insurance coverage required herein.

16.2 Term and Modification of Insurance.

All insurance required under this REPA shall be on an occurrence-basis and shall be in effect during the Term and for a period of two (2) years after the Term. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the date of this REPA and such insurance shall be maintained by Seller, with a retroactive date not later than the retroactive date required above, for a minimum of five (5) years after the Term. If any insurance required to be maintained by Seller hereunder ceases to be reasonably available and commercially feasible in the commercial insurance market, Seller shall provide written notice to Purchaser, accompanied by a certificate from an independent insurance advisor of recognized national standing, certifying that such insurance is not reasonably available and commercially feasible in the commercial insurance market for electric generating plants of similar type, geographic location and design. Upon receipt of such notice, Seller shall use commercially reasonable efforts to obtain other insurance that would provide comparable protection against the risk to be insured and Purchaser shall not unreasonably withhold its consent to modify or waive such requirement.

ARTICLE 17
INDEMNITY

17.1 Indemnity Obligations. Each Party (the "Indemnifying Party") agrees to indemnify, defend and hold harmless the other Party (the "Indemnified Party") from and against all claims, demands, losses, liabilities, penalties and expenses (including reasonable attorneys' fees) for personal injury or death to persons and damage to the Indemnified Party's real property and tangible personal property or facilities or the property of any other person or entity to the extent arising out of, resulting from, or caused by an Event of Default under this REPA, violation of any applicable environmental laws, or by the negligent or tortious acts, errors, or omissions of the Indemnifying Party, its Affiliates, its directors, officers, employees, or agents; provided, however, that notwithstanding the foregoing, each Party shall be responsible for injury or death to such Party's employees, agents and representatives on the Site or in connection with visits thereto or inspections thereof, except to the extent any such injury or death arises from the gross negligence or willful misconduct of the other Party. Nothing in this Section shall enlarge or relieve Seller or Purchaser of any liability to the other for any breach of this REPA. Subject to the foregoing and the next sentence, this indemnification obligation shall apply notwithstanding any negligent or intentional acts, errors or omissions of the Indemnified Party, but the Indemnifying Party's liability to pay damages to the Indemnified Party shall be reduced in proportion to the percentage by which the Indemnified Party's negligent or intentional acts, errors or omissions caused the damages. Neither Party shall be indemnified for its damages resulting from its sole negligence, intentional acts or willful misconduct. These indemnity provisions shall not be construed to relieve any insurer of its obligation to pay claims consistent with the provisions of a valid insurance policy.

17.2 Notification of Claims; Defense. Promptly after receipt by a Party of any claim or notice of the commencement of any action, administrative, or legal proceeding, or investigation as to which the indemnity provided for in this Article may apply, the Indemnified Party shall notify the Indemnifying Party in writing of such fact. The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Party and reasonably satisfactory to the Indemnified Party, provided, however, that if the defendants in any such action include both the Indemnified Party and the Indemnifying Party and the Indemnified Party shall have reasonably concluded that there may be legal defenses available to it which are different from or additional to, or inconsistent with, those available to the Indemnifying Party, the Indemnified Party shall have the right to select and be represented by separate counsel, at the Indemnifying Party's expense, unless a liability insurer is willing to pay such costs; provided further that the Indemnifying Party may settle the claim only if the compromise or settlement includes an unconditional release of the Indemnified Person from all liabilities other than the payment of any money that will be paid by the Indemnifying Party.

17.3 Failure to Defend. If the Indemnifying Party fails to assume the defense of a claim meriting indemnification, the Indemnified Party may at the expense of the Indemnifying Party contest, settle, or pay such claim, provided that settlement or full payment of any such claim may be made only following consent of the Indemnifying Party or, absent such consent, written opinion of the Indemnified Party's counsel that such claim is meritorious or warrants settlement.

17.4 Net of Insurance Proceeds. Except as otherwise provided in this Article, in the event that a Party is obligated to indemnify and hold the other Party and its successors and assigns harmless under this Article 17, the amount owing to the Indemnified Party will be the amount of the Indemnified Party's actual loss net of any insurance proceeds received by the Indemnified Party following a reasonable effort by the Indemnified Party to obtain such insurance proceeds.

ARTICLE 18
LEGAL AND REGULATORY COMPLIANCE

18.1 Compliance with Laws. Each Party shall at all times comply with all laws, ordinances, rules and regulations applicable to it except for any non-compliance which, individually or in the aggregate, could not reasonably be expected to have a material effect on the business or financial condition of the Party or its ability to fulfill its commitments hereunder. As applicable, each Party shall give all required notices, shall procure and maintain all permits, licenses, and inspections required by any Governmental Authority and necessary for performance of this REPA, and shall pay its respective charges and fees in connection therewith.

18.2 Cooperation. Each Party shall cooperate with the other Party in providing such information as may be reasonably requested, to the extent permitted by applicable law and subject to such confidentiality and use limitations as the providing Party may reasonably require, to the extent that the requesting Party requires the same in order to fulfill any regulatory reporting requirements, or to assist the requesting Party in litigation, including administrative proceedings before utility regulatory commissions.

18.3 Removal of Facility. Upon permanent cessation of generation of Renewable Energy from the Facility, Seller shall decommission the Facility, remove the Facility and remediate the Site as, if and when required by law.

ARTICLE 19
ASSIGNMENT, SUBCONTRACTING, AND FINANCING

19.1 No Assignment Without Consent.

Except as permitted in this Article 19, neither Party shall assign this REPA or any portion thereof, without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed; provided (i) at least thirty (30) Days prior notice of any such assignment shall be given to the other Party; (ii) any assignee shall expressly assume the assignor's obligations hereunder, unless otherwise agreed to by the other Party, and no assignment, whether or not consented to, shall relieve the assignor of its obligations hereunder in the event the assignee fails to perform, unless the other Party agrees in writing in advance to waive the assignor's continuing obligations pursuant to this REPA; (iii) no such assignment shall impair any security given by Seller hereunder; and (iv) before the REPA is assigned by Seller, the assignee must first obtain such approvals as may be required by all applicable regulatory bodies. For the avoidance of doubt, a merger of either Party with another Person shall not qualify as an assignment and shall not be subject to the restrictions set forth in this Section 19.1.

(A) Seller's consent shall not be required for Purchaser to assign this REPA to an Affiliate of Purchaser, provided that Purchaser provides assurances and executes documents reasonably required by Seller and the Facility Financiers regarding Purchaser's continued liability for all of Purchaser's obligations under this REPA in the event of any nonperformance on the part of such assignee and that such assignee is a Creditworthy Entity. In the event that the assignee has or obtains an investment grade senior unsecured debt rating equivalent to or better than the senior unsecured debt rating of Purchaser (but in no event worse than the equivalent of BBB), then Seller agrees to relieve Purchaser from its obligations under this REPA if Purchaser requests to be so relieved in a written notice provided to Seller.

(B) Seller shall have the right, without Purchaser's prior written consent, to assign this REPA (i) subject to the provisions of Section 19.2, to a purchaser of all or substantially all of the assets of Seller; (ii) to an Affiliate of Seller; (iii) subject to the provisions of Section 19.2, in connection with a merger of Seller with another Person or any other transaction resulting in a direct or indirect change of control of Seller, or (iv) for collateral purposes to the Facility Financing Representative or any Facility Financier provided that the Parties and the Facility Financing Representative have executed the applicable Consent and Agreement; and in any event provided that such purchaser, Affiliate or the Person surviving such merger, as applicable, (x) meets the requirements of this Section 19.1, (y) complies with the requirements of Section 11.1, and (z) is a Qualified Operator.

19.2 Right of First Offer.

(A) Provided that no Event of Default by Purchaser is continuing, Seller (or any direct or indirect parent of Seller) shall not sell or transfer all or any portion of the Facility or all or any portion of its direct or indirect equity interests in Seller, unless prior to such sale or transfer, Seller provides written notice of such sale or transfer to Purchaser. Such notice may, but is not required to, contain a description of the price and other terms upon which Seller (or any direct or indirect parent of Seller) desires to sell or transfer such interest in the Facility (or direct or indirect equity interests in Seller). If Purchaser desires to enter into negotiations with Seller regarding the sale or transfer of the interest(s) that are the subject of the notice, Purchaser shall notify Seller of such decision within fifteen (15) days of receipt of Seller's notice. Upon Seller's receipt of such notice, Purchaser and Seller shall negotiate in good faith, on an exclusive basis for no more than sixty (60) days (unless a longer period is otherwise mutually agreed to), the terms of the sale or transfer of the Facility (or direct or indirect equity interests in

Seller) to Purchaser or any Affiliate of Purchaser. Seller will provide in a timely manner, information regarding the Facility (and, if applicable, direct or indirect equity interests in Seller) which is reasonable or customary to allow Purchaser to perform due diligence and to negotiate in good faith for the purchase of the Facility (or direct or indirect equity interests in Seller).

(B) In the event that Purchaser does not exercise its right to negotiate pursuant to Section 19.2(A), Seller must comply with Section 19.1 in any assignment of Seller's rights, interests or obligations herein to a purchaser of the Facility.

(C) In the event that Seller (or any direct or indirect parent of Seller) does not consummate the sale or transfer of the interests offered to Purchaser in accordance with Section 19.2(A) within one hundred eighty (180) Days of the date that is the later of (i) Purchaser's declining to enter into negotiations with Seller after Seller's notice pursuant to Section 19.2(A), or (ii) the end of the exclusive negotiation period between Seller and Purchaser pursuant to Section 19.2(A), Seller (or any direct or indirect parent of Seller) shall not sell or transfer all or any portion of the Facility (or all or any portion of its direct or indirect equity interests in Seller), unless prior to such sale or transfer it complies with the provisions of Section 19.2(A).

(D) The provisions of this Section 19.2 shall terminate upon termination of this Agreement by Seller or upon the assignment of this REPA by Purchaser to any Person other than an Affiliate of Purchaser.

19.3 <u>Accommodation of Facility Financiers</u>.

To facilitate Seller's obtaining of financing with respect to the Facility, Purchaser shall make reasonable efforts to enter into the applicable Consent and Agreement, and to provide such other certifications, representations or other documents as may be reasonably requested by Seller or the Facility Financing Representative; provided, that in responding to any such request, Purchaser shall have no obligation to enter into any agreement that materially adversely affects any of Purchaser's rights, benefits, risks or obligations under this REPA. Seller shall reimburse, or shall cause the Facility Financing Representative to reimburse, Purchaser for the incremental amount of direct expenses (including the reasonable fees and expenses of counsel) incurred by Purchaser in the preparation, negotiation, execution and delivery of the applicable Consent and Agreement and any other documents requested by Seller or the Facility Financiers, and provided by Purchaser, pursuant to this Section 19.3.

19.4 <u>Notice of Facility Financier Action</u>.

Within ten (10) Days following Seller's receipt of each written notice from the Facility Financiers of default, or Facility Financiers' intent to exercise any remedies, under the Financing Documents, Seller shall deliver a copy of such notice to Purchaser.

19.5 <u>Transfer Without Consent is Null and Void</u>.

Any sale, transfer, or assignment of any interest in the Facility or in this REPA made without fulfilling the requirements of the REPA shall be null and void and shall constitute an Event of Default pursuant to Article 12.

19.6 Subcontracting.

Seller may subcontract its duties or obligations under this REPA without the prior written consent of Purchaser, provided, that no such subcontract shall relieve Seller of any of its duties or obligations hereunder.

ARTICLE 20
MISCELLANEOUS

20.1 Waiver.

Subject to the provisions of Section 13.9(B), the failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this REPA, or to take advantage of any of its rights there under, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

20.2 Taxes.

(A) Each Party shall use reasonable efforts to implement the provisions of and to administer this REPA in accordance with the intent of the Parties to minimize all Taxes, so long as neither Party is materially adversely affected by such efforts. Notwithstanding the foregoing, neither Party shall be obligated to incur any financial burden to reduce taxes for which the other Party is responsible hereunder.

(B) Seller shall pay or cause to be paid (and shall indemnify and hold Purchaser harmless from and against) all sales, use, excise, ad valorem, transfer and other similar taxes that are imposed by any taxing authority (individually, a "Tax" and collectively, "Taxes") on or with respect to the Facility or the sale of Renewable Energy Products incurred prior to the delivery of Renewable Energy Products to the Point of Delivery. Purchaser shall pay or cause to be paid (and shall indemnify and hold Seller harmless from and against) all Taxes on or with respect to the sale of Renewable Energy Products incurred upon and after the delivery of Renewable Energy Products to the Point of Delivery (other than ad valorem, franchise, income, or commercial activity taxes, and transactional taxes or fees imposed by law on the Seller that are related to the sale of Renewable Energy Products and are, therefore, the responsibility of the Seller). If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, the responsible Party shall promptly reimburse the other for such Taxes.

(C) In the event any of the sales of Renewable Energy Products hereunder are exempt or excluded from any particular Tax(es) payable by Purchaser, Purchaser shall provide Seller with all necessary documentation within thirty (30) days after the execution of this REPA to evidence such exemption or exclusion (or, with regard to any such Tax(es) enacted after the Effective Date, Purchaser shall provide Seller with such documentation before the date on which the enactment requires the delivery of documentation to Seller in order to effect an exclusion or exemption from such Tax(es)). In the event Purchaser does not provide such documentation, then Purchaser shall indemnify, defend and hold Seller harmless from any liability with respect to Tax(es) to which Purchaser is exempt or excluded.

20.3 Fines and Penalties.

(A) Seller shall pay when due all fees, fines, penalties or costs to the extent incurred by Seller or its agents, employees or contractors for noncompliance by Seller, its employees, or subcontractors with any provision of this REPA, or any contractual obligation, permit or requirements of law except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by Seller and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, penalties, or costs are claimed or assessed against either Party by any Governmental Authority due to noncompliance by the other Party with this REPA, any requirements of law with which compliance is required by this REPA, any permit or contractual obligation, or, if the work of the other Party or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority due to the other Party's noncompliance with any requirements of law with which compliance is required by this REPA, permit, or contractual obligation, penalized Party shall indemnify and hold other Party harmless against any and all reasonable losses, liabilities, damages, and claims suffered or incurred by other Party, including claims for indemnity or contribution made by third parties against other Party, except to the extent other Party recovers any such losses, liabilities or damages through other provisions of this REPA.

20.4 Rate Changes.

The terms and conditions and the rates for service specified in this REPA shall remain in effect for the term of the transaction described herein. Absent the Parties' written agreement, this REPA shall not be subject to change by application of either Party pursuant to Section 205, 206 or 306 of the Federal Power Act.

Absent the agreement of all parties to the proposed change, the standard of review for changes to this REPA whether proposed by a Party, a non-party, or the Federal Energy Regulatory Commission acting *sua sponte* shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956), as clarified by Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish, 554 U.S. ___ (2008) (the "Mobile-Sierra doctrine), or such other standard of review permissible to preserve the intent of the parties pursuant to this Section to uphold this REPA without modification.

20.5 Disclaimer of Third Party Beneficiary Rights.

In executing this REPA, neither Party does, nor should it be construed to, extend its credit or financial support for the benefit of any third parties, including those lending money to or having other transactions with the other Party. Except with respect to the Consent and Agreement, nothing in this REPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any person not a party to this REPA.

20.6 Relationship of the Parties.

(A) This REPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party nor to create any agency relationship between the Parties or impose any fiduciary responsibility on either Party or create any trust or trust obligations on either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of persons to perform its obligations under this REPA, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the persons employed by Seller shall be considered employees of Purchaser for any purpose; nor shall Seller represent to any person that he or she is or shall become a Purchaser employee.

20.7 Equal Employment Opportunity Compliance Certification.

Seller acknowledges that as a government contractor Purchaser is subject to various federal laws, executive orders, and regulations regarding equal employment opportunity and affirmative action. These laws may also be applicable to Seller as a subcontractor to Purchaser. Seller shall comply with all applicable equal opportunity and affirmative action federal laws, executive orders, and regulations, including, if applicable, 41 C.F.R. §60-1.4(a)(1-7).

20.8 Survival of Obligations.

Cancellation, expiration, or earlier termination of this REPA shall not relieve the Parties of obligations that by their nature should survive such cancellation, expiration, or termination, prior to the term of the applicable statute of limitations, including warranties, remedies, or indemnities, which obligations shall survive for the period of the applicable statute(s) of limitation.

20.9 Severability.

In the event any of the terms, covenants, or conditions of this REPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of the REPA and their application not adversely affected thereby shall remain in force and effect; provided, however, that Purchaser and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this REPA with a view toward effecting the purposes of this REPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

20.10 Complete Agreement; Amendments.

The terms and provisions contained in this REPA constitute the entire agreement between Purchaser and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Purchaser and Seller with respect to the sale of Renewable Energy Products from and associated with the Facility. This REPA may be amended, changed, modified, or altered, provided that such amendment, change, modification, or alteration shall be in writing and signed by both Parties hereto.

20.11 Binding Effect.

This REPA, as it may be amended from time to time pursuant to this Article, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

20.12 Headings.

Captions and headings used in this REPA are for ease of reference only and do not constitute a part of this REPA.

20.13 Counterparts.

This REPA may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

20.14 Governing Law.

The interpretation and performance of this REPA and each of its provisions shall be governed and construed in accordance with the laws of the State of New York, without regard to its conflicts of laws provisions.

20.15 Confidentiality.

This REPA and any information provided by either Party to the other Party pursuant to this REPA and labeled "CONFIDENTIAL" or with words of similar meaning will be utilized by the receiving Party solely in connection with the purposes of this REPA and will not be disclosed by the receiving Party to any third party, except with the providing Party's consent, and upon request of the providing Party will be returned thereto, except that the receiving Party will not be obligated to return any such information contained in documents generated by the receiving Party that: (1) reflect or refer to confidential information provided by the disclosing Party; and (2) are stored electronically by the receiving Party. With respect to any such retained electronically stored confidential information, the receiving Party will continue to comply with the obligations of this Section 20.15. Notwithstanding anything herein to the contrary, the Parties acknowledge and agree that such confidential information may be disclosed to (i) the Interconnection Provider, the Transmission Operator, Affiliates or any other Person (including subcontractors, consultants, accountants, financial advisors, experts, legal counsel and other professional advisors to the Parties) as required for settlement and billing or otherwise to perform under or administer this REPA; and (ii) in case of Seller, to Facility Financiers or potential Facility Financiers, potential bidders and bidders for, and potential purchasers and purchasers of, direct or indirect ownership interests in the Facility (including direct or indirect interests in the equity interests of Seller). To the extent that such disclosures are necessary, the Parties also agree that they will in disclosing such information seek to preserve the confidentiality of such disclosures, by requiring a party receiving confidential information to be bound by the terms of this REPA applicable to such a confidential information. Without limiting the foregoing, this Section 20.15 will not prevent a Party from providing confidential information to any Governmental Authority formally or otherwise, as required in connection with any regulatory proceeding, as required for obtaining any regulator approval or making any regulatory filing, provided that each Party agrees to cooperate with the other to maintain the confidentiality of the provisions of this REPA by requesting confidential treatment with all filings to the extent appropriate and permitted by applicable law. This provision will not prevent either Party from providing any confidential information received from the other Party to any court or regulatory proceeding or in accordance with a proper discovery request or in response to the reasonable request or need of any Governmental Authority charged with regulating the disclosing Party's affairs or in accordance with the request of any applicable stock exchange, provided that, if feasible, the disclosing Party will give prior notice to the other Party of such disclosure and, if so requested by such other Party, will have used all reasonable efforts to oppose or resist the requested disclosure, as appropriate under the circumstances, or to otherwise make such disclosure pursuant to a protective order or other similar arrangement for confidentiality.

20.16 Forward Contract.

The Parties acknowledge and agree that this REPA and the transactions contemplated by this REPA constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that each Party is a "forward contract merchant" within the meaning of the United States Bankruptcy Code.

[remainder of this page intentionally left blank]

IN WITNESS WHEREOF, the Parties have executed this REPA.

Seller:

ecoPower Generation-Hazard LLC

By: ______________________________

By: ______________________________

Purchaser:

Kentucky Power Company

By:______________________________

EXHIBIT A

FACILITY MILESTONES

EXHIBIT B

FACILITY DESCRIPTION AND SITE MAPS

Facility Description

EXHIBIT C

CONTRACT RATE
($ Per MWh)

[redacted]

EXHIBIT D

NOTICE ADDRESSES

Purchaser	Seller
Notices and Insurance: **Other than invoices:** Kentucky Power Company c/o American Electric Power Service Corporation 155 West Nationwide Boulevard Columbus, OH 43215 Attn: Contract Administration Fax: (614) 583-1606 **with copies to:** American Electric Power Service Corporation 155 West Nationwide Boulevard Columbus, OH 43215 Attn: Director, Credit Risk Department Fax: (614) 583-1604 **and** Attn: Chief Counsel, CO&L American Electric Power Service Corporation 155 West Nationwide Boulevard Columbus, OH 43215 Attn: Chief Counsel Fax: (614) 583-1603 **and** Attn: Risk and Insurance Management American Electric Power Service Corporation 1 Riverside Plaza Columbus, OH 43215	**Notices:** **Notices (other than operational notices):** **With copies to:**

Contract Administration Committee Representative: Jay Godfrey (614) 583-6162 jfgodfrey@aep.com **Alternate:** To be designated in writing by Purchaser at or prior to the first meeting of the Contract Administration Committee	**Contract Administration Committee Representative:** **Alternate:**

EXHIBIT E

INSURANCE COVERAGE

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EXHIBIT F

SELLER'S REQUIRED PERMITS, CONSENTS, APPROVALS, LICENSES AND AUTHORIZATIONS

[To be provided by Seller]

EXHIBIT G

POINT OF DELIVERY

[To be provided by Seller]

EXHIBIT H-1

INTENTIONALLY OMITTED

EXHIBIT H-2

INTENTIONALLY DELETED

EXHIBIT I

CALCULATION OF OUTPUT SHORTFALL LIQUIDATED DAMAGES

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EXHIBIT J

INTENTIONALLY OMITTED

EXHIBIT K

FORM OF AVAILABILITY NOTICE

Effective Date ____________

Time ____________________

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EXHIBIT L

FORM OF LETTER OF CREDIT

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EXHIBIT M

FORM OF GUARANTY

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Kentucky Power Company

REQUEST

Beyond those materials already provided in response to questions Q1-1 through Q1-5 above, provide a copy of all other correspondence and documents exchanged between Kentucky Power and ecoPower regarding the transactions described in the Application.

RESPONSE

The Company objects to this request to the extent it seeks communications and documents protected by the attorney-client privilege and/or the attorney work-product doctrine.

The Company further objects to this request to the extent it seeks all documents regarding the transaction between the Company and ecoPower, as such the request is overly broad and unduly burdensome. The request purports to require a search of documents involving potentially thousands of corporate records, and their review concerning confidentiality and privilege. As of May 22, 2013 over 5,000 documents were identified as being potentially responsive to this request.

Without waiving its objections, the Company states as follows:

The Company is searching the electronic files of the following individuals for responsive documents:
Jay Godfrey
Joe Karrasch
Jay Jadwin
Greg Pauley
Mark Overstreet

Documents will be produced on an ongoing basis.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Provide a copy of all correspondence and documents exchanged between Kentucky Power and Greenleaf Power LLC regarding the transactions described in the Application.

RESPONSE

See the Company's response to KIUC 1-6.

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Provide a copy of all correspondence and documents exchanged between Kentucky Power and Denham Capital regarding the transactions described in the Application.

RESPONSE

See the Company's response to KIUC 1-6.

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Provide a copy of all correspondence and documents exchanged between Kentucky Power and any of the witnesses that provided testimony in support of the Application regarding the transactions described in the Application.

RESPONSE

See the Company's response to KIUC 1-6.

WITNESS: Gregory G. Pauley/Jay F. Godfrey/Ranie K. Wohnhas

Kentucky Power Company

REQUEST

Provide a copy of all correspondence and documents exchanged internally within Kentucky Power and AEP regarding the transactions described in the Application.

RESPONSE

See the Company's response to KIUC 1-6.

WITNESS: Greogry G. Pauley/Jay F.Godfrey

Kentucky Power Company

REQUEST

If Kentucky Power did not conduct a recent solicitation (i.e., within the last 24 months) to gauge and assess whether or not the ecoPower transaction was the best resource for Kentucky Power's customers and that the transaction's pricing was fair, just, and reasonable, explain in narrative form why it did not.

RESPONSE

Without accepting the characterization of the purpose or effect of an RFP, please see the Company's response to KIUC 1-1. The ecoPower REPA was presented to KPCo as a unique opportunity and the Company entered into the agreement for the reasons identified in the pre-filed testimony of Gregory G. Pauley pages 6-9.

WITNESS: Jay F. Godfrey/Gregory G. Pauley

Kentucky Power Company

REQUEST

Refer to Mr. Pauley's Testimony, page 6 beginning on line 18.

a. If the REPA is not the least cost alternative to supply the contracted capacity and energy; is it the least cost "renewable" capacity and energy?

b. Did Kentucky Power conduct an RFP to determine the least cost "renewable" capacity and energy? If so, then please provide all reports, analyses, workpapers, and documentation of any type in support of your answer. If not, then please explain why it did not.

RESPONSE

a. & b. KPCo did not conduct an RFP to determine the least cost "renewable" capacity and energy. See the Company's response to KIUC 1-1 and KIUC 1-11.

WITNESS: Gregory G. Pauley/ Jay F. Godfrey

Kentucky Power Company

REQUEST

Did Kentucky Power perform any studies in order to identify the least-cost means of providing energy and capacity to Kentucky Power. Please provide all reports, analyses, workpapers, and documentation of any type that was produced from conducting those studies. If no studies were performed, please explain why they were not performed. This information should be provided electronically with all formulas intact and no pasted in values.

RESPONSE

There were no studies performed.

Please see the Company's response to KIUC 1-11.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Provide the following estimated annual data separately for the ecoPower facility. Provide all source documents relied on and/or that otherwise support your answer:

a. Capacity of Units
b. Net Generation (MWh)
c. Capacity Factor
d. Fuel Cost
e. Forced Outage Rate
f. O&M Expense
g. Planned Outage Frequency and Duration
h. Availability Factor

RESPONSE

Please see KIUC 1-14 CONFIDENTIAL Attachments 1 & 2 for the requested information. Confidential treatment is being sought for Attachment 2 in entirety.

WITNESS: Jay F Godfrey

ecoPower Generation

Confidential

Proposal Data Sheet
6/30/2011

Bundled All-In Price

Seller: *ecoPower Generation - Hazard, LLC*

Product and Generation Characteristics:
Proposal Description ecoPower Generation - Hazard, LLC, Perry County Biomass Unit 1, nominally 58 MW Net located at 1244 Coal Fields Industrial Drive Chavies, KY 41727-9100. The plant burns a blend of wood from the wood products industry and low-grade logs that are chipped on-site. The plant is Rankine-cycle Fluid Bed Boiler technology, STG, Air-Cooled Condenser, etc.
Generation Source Description Solid woody biomass fuel in a traditional Rankine-cycle power plant
Transmission Interconnection Point of the Source Engle Substation in Kentucky Power (AEP), Perry Co., KY
Point of Interconnection to the Grid Same (PJM Interconnection)
Fuel Price [redacted]
Start Date and Term of Contract 12/1/2013, Pre-start option for commissioning, 20-year Term
Summer Firm Capacity Amount [redacted]
Summer Maximum Dispatch Capacity Amount [redacted]
Summer Minimum Dispatch Capacity Amount [redacted]
Expected Heat Rate [redacted]
Winter Firm Capacity Amount [redacted]
Winter Maximum Dispatch Capacity Amount [redacted]
Winter Minimum Dispatch Capacity Amount [redacted]
Output in 10 minutes [redacted]
Ramp capability [redacted]
Start-up time to minimum capability [redacted]
Start-up time to maximum capability [redacted]
Minimum run tim[redacted]
Minimum down time [redacted]
Constraints on production time This proposal is for a base-load plant
Forced Outage Rate [redacted]
Guaranteed Availability [redacted]
Planned Outage Schedule[redacted]

Pricing Information:
Sale Price[redacted]
Energy Pricing:
[redacted]

ADDRESS 1256 Manchester Street
Lexington KY 40504
United States of America
PHONE ph: 859-685-1106
fx: 859-252-6964
WEB info@ecopg.com
www.ecopg.com

KIUC 1-14 ATTACHMENT 2
REDACTED IN ENTIRETY

Kentucky Power Company

REQUEST

Refer to page 5 of Mr. Godfrey's Testimony. Identify all biomass facilities that AEP owns, operates. For any identified facilities provide the following information. Provide all source documents relied on and/or that otherwise support your answer:

a. Capacity of Units
b. Net Generation (MWh)
c. Capacity Factor
d. Fuel Cost
e. Forced Outage Rate
f. O&M Expense
g. Commercial operation date
h. Type of fuel source
i. Combustion technology
j. Facility location
k. Planned Outage Frequency and Duration
l. Availability Factor

RESPONSE

AEP does not own or operate any biomass facilities.

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Identify all biomass facilities that AEP takes power from under contract. For any identified facilities provide a copy of the contract or agreement between AEP and the owner/operated of the biomass facility. For any identified facilities provide the following information. Provide all source documents relied on and/or that otherwise support your answer:

a. Capacity of Units
b. Net Generation (MWh)
c. Capacity Factor
d. Fuel Cost
e. Forced Outage Rate
f. O&M Expense
g. Total purchase cost per MWh by year.
h. Planned Outage Frequency and Duration
i. Availability Factor

RESPONSE

AEP does not take power under contract from any biomass facilities.

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Please provide all reports, analyses, workpapers, and documentation in support of Exhibit JFG-2. For the Agreements listed provide the following information. Provide all source documents relied on and/or that otherwise support your answer:

a. Capacity of Units
b. Net Generation (MWh)
c. Capacity Factor
d. Forced Outage Rate
e. O&M Expense
f. Total purchase cost per MWh by year.
g. Planned Outage Frequency and Duration
h. Availability Factor

RESPONSE

Kentucky Power objects to this request as it is unduly burdensome, seeks irrelevant information, and is unlikely to lead to the discovery of admissible evidence. Kentucky Power is not a party to purchased power agreements containing the information requested and the information is subject to disclosure only in the affected utility's jurisdiction.

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Refer to Exhibit JFG-1, page 73. Will construction on the Facility start on May 23, 2013 without Commission approval of the REPA?

RESPONSE

Construction work for the Chipper Building began on April 22, 2013.

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Provide all studies and analysis demonstrating Kentucky Power's need for the energy and capacity supplied in the REPA. Please provide all reports, analyses, workpapers, and documentation of any type that was produced from conducting such studies or analysis. This information should be provided electronically with all formulas intact and no pasted in values.

RESPONSE

There are no studies or analysis. Please see the Company's response to KIUC 1-11.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Please provide the estimated capacity value of the proposed facility for PJM purposes. Provide all documentation relied on to make this estimate.

RESPONSE

PJM has not yet determined the PJM capacity value of the facility. Based on the expected capacity factor of 88%, and the PJM Capacity Factor guidelines as described in PJM Manual 18, the expected capacity value from a PJM perspective is estimated to be in the 85% to 95% range. Please refer to KIUC 1-20 Attachment 1 for the specific PJM guidelines for the calculation of PJM capacity values for new generation resources.

WITNESS: Jay F Godfrey

PJM Manual 18:
PJM Capacity Market

Revision: 18
Effective Date: March 28, 2013

Prepared by
PJM Capacity Market Operations

PJM Manual 18:

PJM Capacity Market

Table of Contents

Table of Exhibits

Approval

Approval Date: 03/28/2013
Effective Date: 03/28/2013

Jeff Bastian, Manager

Capacity Market Operations

Current Revision

Revision 18 (03/28/2013):

- Proposed revisions for Demand Resource Sell Offer Plan Enhancements (Sections 4.3.1, 4.3.3, 4.3.6, and 11.4.7, Attachments C and D)

Introduction

Welcome to the PJM Manual for *PJM Capacity Market*. In this Introduction you will find information about PJM Manuals in general, an overview of this PJM Manual in particular, and information on how to use this manual.

- What you can expect from the PJM Manuals (see "About PJM Manuals").
- What you can expect from this PJM Manual (see "About This Manuals).
- How to use this manual (see "Using This Manual").

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and billing
- PJM administrative services
- Miscellaneous.

About This Manual

The PJM Manual for ***PJM Capacity Market*** is one of the PJM procedure manuals. This manual focuses on the capacity markets, including the Reliability Pricing Model and the Fixed Resource Requirement Alternative, and the requirements for resource providers and Load Serving Entities (LSEs) to participate in these markets and their responsibilities as signatories to the Open Access Transmission Tariff, Reliability Assurance Agreement and Operating Agreement of PJM Interconnection, L.L.C.

This manual also refers to other PJM manuals, which define in detail the operating procedures, obligations, reporting requirements, and accounting procedures established to ensure reliable and efficient capacity market operation.

The PJM Manual for ***PJM Capacity Market** consists* of 11 sections and 5 attachments (labeled A through E). Both the sections and the attachments are listed in the table of contents beginning on page ii.

Intended Audience

The intended audiences for this PJM Manual for *PJM Capacity Market* are:

- Applicants to the RAA, OA and OATT Operating Agreement of PJM Interconnection, L.L.C.

- Resource providers and those interested in providing adequate Capacity Resources that will be made available to provide reliable service to loads within the PJM Region.
- Load Serving Entities (LSEs) for load served in the PJM Region.
- PJM Members
- PJM staff

References

There are other PJM documents that provide both background and detail on specific topics. These documents are the primary source for specific requirements and implementation details. This manual does not replace any of the information in those reference documents. The references for the PJM Manual for *PJM Capacity Market* are:

- PJM Manual for Scheduling (M-11)
- PJM Manual for Generation and Transmission Interconnection Planning (14b)
- PJM Manual for Load Data Systems (M-19).
- PJM Manual for Reserve Requirements (M-20).
- PJM Manual for Rules and Procedures for Determination of Generating Capability (M-21)
- PJM Manual for Generator Resource Performance Indices (M-22).
- PJM Manual for Open Access Transmission Tariff Accounting (M-27).
- PJM Manual for Billing (M-29).

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with the "big picture." Then we present details, procedures or references to procedures found in other PJM manuals.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections and attachments
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions
- Attachments that include additional supporting documents, forms, or tables
- A section at the end detailing all previous revisions of this PJM Manual.

Section 1: Overview of the PJM Capacity Market

Welcome to the *Overview of the PJM Capacity Market* section of the *PJM Manual for the PJM Capacity Market*. In this section, you will find the following information:

- An overview description of the PJM Capacity Market (see "Overview of the PJM Capacity Market")
- The business rules for participation in the PJM Capacity Markets (see "Participation in the PJM Capacity Market")
- A definition and purpose of the Reliability Pricing Model (see "Definition and Purpose of the Reliability Pricing Model")
- The timeframe for implementation of the Reliability Pricing Model (see "Implementation of the Reliability Pricing Model")

1.1 Overview of the PJM Capacity Market

The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. In PJM, the capacity market structure provides transparent information to enable forward capacity market signals to support infrastructure investment. The capacity market design provides a forward mechanism to evaluate the ongoing reliability requirements in a transparent way to provide opportunity for generation, demand response, energy efficiency, price responsive demand and transmission solutions.

In the PJM Region, the basis for the capacity market design is the Reliability Pricing Model (RPM). The goal of RPM is to align capacity pricing with system reliability requirements and to provide transparent information to all market participants far enough in advance for actionable response to the information. In RPM, the fundamental elements to achieve this are:

- Locational Capacity Pricing to recognize and quantify the locational value of capacity
- Variable Resource Requirement mechanism to adjust price based on the level of resources procured
- Forward Commitment of supply by generation, demand resources and qualified transmission upgrades cleared in a multi-auction structure
- A Reliability Backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability

The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement (FRR) Alternative. The Fixed Resource Requirement Alternative provides a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

Unless otherwise specified, the rules presented throughout this Manual are focused on the Reliability Pricing Model. Information on the Fixed Resource Requirement Alternative can be found in ***Section 11 of this Manual*** and on PJM.com.

1.2 Participation in the PJM Capacity Market

Participants in the PJM Capacity Market, both Load Serving Entities and resource providers, must comply with all applicable provisions of the PJM Open Access Transmission Tariff, PJM Operating Agreement, and the PJM Reliability Assurance Agreement. PJM Capacity Market participants must be signatories of the appropriate Agreements and Full Members of PJM. All participants must comply with the procedures and requirements as set forth by these agreements and in PJM Manuals.

1.2.1 Participation of Load Serving Entities

Participation by Load Serving Entities (LSEs) in the RPM for load served in the PJM region is mandatory, except for those LSEs that have elected the Fixed Resource Requirement (FRR) Alternative and submitted an approved FRR Capacity Plan for their load served in an FRR Service Area. Under RPM, each LSE that serves load in a PJM Zone during the Delivery Year shall be responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in the Zone multiplied by the Final Zonal Capacity Price applicable to that Zone. LSEs may choose to hedge their Locational Reliability Charge obligations by directly offering and clearing resources in the Base Residual Auction and Second Incremental Auction or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction. Such action may wholly or partially offset an LSE's Locational Reliability Charges during the Delivery Year depending upon how the clearing prices of the resources compare to the Final Zonal Capacity Prices that apply to their unforced capacity obligations.

Participants with Non-Zone Load, as defined in the PJM Agreements, may be included in the Reliability Pricing Model depending if the load that is located outside of the PJM Region is included in the PJM load forecasts and served by generation resources located within the PJM Region. The treatment of Non-Zone Load is described in Section 7 of this Manual.

1.2.2 Participation of Resource Providers

Resource providers with existing generation, planned generation, bilateral contracts for unit-specific capacity resources, existing Demand Resources, Planned Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades may participate in PJM's Capacity Market, either in PJM's Reliability Pricing Model or the Fixed Resource Requirement Alternative, if these products meet the requirements specified in this Manual. Existing generation that is located outside of the PJM market footprint may also be offered into PJM's Capacity Market, either in the Reliability Pricing Model or the Fixed Resource Requirement Alternative, if the external generation meets the requirements specified in the PJM Manuals and PJM Agreements.

Participation is mandatory for resource providers with:

- Available unforced capacity from existing generation located within the PJM market footprint; or
- Bilateral contracts for available unit-specific capacity resources that are existing generation units located within the PJM market footprint.

- Generation is treated as existing for the purpose of must-offer requirement and mitigation provisions when the generation is (a) in service at the commencement of an RPM Auction or (b) not yet in service but has cleared an RPM Auction for any prior Delivery Year. The Minimum Offer Price Rule (MOPR), as described in Section 5.3.5, applies to a Planned Generation Resource until the first year for which it clears an RPM Auction.

Resource providers do have the option to export available capacity outside the PJM market footprint if the generator is exporting per the requirements specified in PJM Manuals and PJM Agreements.

Participation is voluntary for resource providers with:

- External generation
- Planned generation (including planned upgrades to existing units)
- Planned external generation (including planned upgrades to existing units)
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources
- Qualifying Transmission Upgrades.

All participation by resource providers is subject to the market power mitigation rules described in Attachment DD, Section 6 of the PJM Open Access Transmission Tariff.

1.2.3 Participation of PRD Providers

Starting with the 2016/2017 Delivery Year, PRD Providers may participate in PJM's Capacity Market, either in PJM's Reliability Pricing Model or the Fixed Resource Requirement Alternative. A PRD Provider is a PJM Member that is (1) a LSE that provides PRD; or (2) an entity without direct load serving responsibilities that has entered contractual arrangements with end-use customers served by a LSE that satisfy the eligibility criteria for PRD as specified in this Manual.

1.3 Definition and Purpose of the Reliability Pricing Model

The Reliability Pricing Model is the PJM resource adequacy construct that ensures that adequate Capacity Resources, including planned and existing Generation Resources, Energy Efficiency Resources and planned and existing Demand Resources will be made available to provide reliable service to loads within the PJM Region.

The purpose of the RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM is also designed to add stability and a locational nature to the pricing signal. The RPM is a multi-auction structure designed to procure resource and PRD commitments to satisfy the region's unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

- *Base Residual Auction* - The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. The Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.

- *Incremental Auctions* – At least three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.
- The First, Second, and Third Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.
- A Conditional Incremental Auction may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.
- *The Bilateral Market* – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge. The bilateral market is facilitated through the eRPM system.

1.4 Implementation of the Reliability Pricing Model

The implementation of the Reliability Pricing Model began with the 2007/2008 Delivery Year. PJM's Planning Period is defined as an annual period from June 1 to May 31. The Delivery Year is the Planning Period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012 - May 31, 2013 Planning Period.

The Transition Period of the RPM took place during the 2007/2008 through 2010/2011 Delivery Years.

The steady-state condition of the RPM began with the 2011/2012 Delivery Year. Unless otherwise specified, the rules and timeframes presented throughout this Manual are for the steady-state condition of RPM. Information on the Transition Period can be found in an ***Appendix C of this Manual*** and on PJM.com.

Section 2: Resource Adequacy

Welcome to the *Resource Adequacy* section of the *PJM Manual for the PJM Capacity Market*. In this section, you will find the following information:

- An overview description of resource adequacy (see "Overview of Resource Adequacy")
- The role of load deliverability in the Reliability Pricing Model (see "Role of Load Deliverability in the Reliability Pricing Model")
- The business rules for Locational Constraints in the Reliability Pricing Model ("see Locational Constraints in the Reliability Pricing Model")
- The definitions of Reliability Requirements (see "Reliability Requirements")

2.1 Overview of Resource Adequacy

The purpose of PJM RTO resource adequacy is to determine the amount of capacity resources that can be required to serve the forecast load that satisfies the PJM reliability criterion. PJM performs an assessment of resource adequacy each year for a ten-year future period. The analysis considers load forecast uncertainty, forced outages of generation capacity resources, as well as planned and maintenance outages. In PJM, studies are performed using the installed capacity values of resources. The reliability value of a resource depends on two variables: the installed capacity of the resource and a measure of the probability that a resource will not be available due to forced outages or forced de-ratings. The reliability criterion is based on Loss of Load Expectation (LOLE) not exceeding one occurrence in ten years. The resource requirement to meet the reliability criterion is expressed as the Installed Reserve Margin (IRM) as a percentage of forecast peak load.

2.1.1 Installed Reserve Margin

The Installed Reserve Margin (IRM) for the Delivery Year is the measure calculated to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the PJM Reliability Principles and Standards. The IRM is determined by PJM in accordance with ***the PJM Reserve Requirements Manual (M-20).***

The ***Installed Reserve Margin*** (IRM) is approved by the PJM Board of Managers and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. An Updated IRM is approved by the PJM Board of Managers and posted one month prior to its use in an Incremental Auction for the Delivery Year. The Updated IRM that is posted for the Third Incremental Auction for the Delivery Year is the final IRM for the Delivery Year.

2.1.2 Peak Load Forecasts

PJM produces peak load forecasts for use in the RPM auction clearing processes and for planning purposes. In RPM, the load forecasts will be used to determine the RTO Reliability Requirement. PJM will determine ***annual peak load forecasts*** for the RTO and zones for use in the RPM Auction clearing process.

The Preliminary RTO Peak Load Forecast and the Preliminary Zonal Peak Load Forecasts for the Delivery Year are determined by PJM in accordance with ***the Load Data Systems Manual (M-19).***

The Preliminary RTO and Zonal Peak Load Forecasts are determined and posted by February 1 prior to the Base Residual Auction for the Delivery Year.

Updated RTO and Zonal Peak Load Forecasts for the Delivery Year are determined by PJM in accordance with the Load Data Systems Manual.

Updated RTO and Zonal Peak Load Forecasts are posted no later than one month prior to the First and Second Incremental Auctions.

The Final RTO Peak Load Forecast and the Final Zonal Peak Load Forecasts for the Delivery Year are determined by PJM *in accordance with the Load Data Systems Manual.*

The ***Final RTO and Zonal Peak Load Forecasts*** are posted no later than one month prior to the Third Incremental Auction.

Load forecasts are also used in the determination of other planning and auction parameters such as Capacity Emergency Transfer Limit (CETL), Capacity Emergency Transfer Objective (CETO), and RPM Zonal Scaling Factors. These parameters are discussed in detail in later sections of this Manual.

2.1.3 Pool-wide Average EFORd

To account for the forced outage rates of generation capacity resources, an Equivalent Forced Outage Rate (EFORd) for each generating unit in the PJM RTO is calculated. Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. See ***Generator Resource Performance Indices Manual (M-22)*** for equations and details.

The Pool-wide Average EFORd for the Delivery Year is the average of the forced outage rates based on five years history, weighted for unit capability and expected time in service, attributable to all units that are planned to be in service during the Delivery Year. The Pool-Wide Average EFORd will not include forced outage events that are outside management control (referred to as OMC events). The Pool-wide Average EFORd is determined by PJM in accordance with ***the PJM Reserve Requirements Manual (M-20).***

The ***Pool-wide average EFORd*** is posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. An updated Pool-wide average EFORd is posted one month prior to its use in an Incremental Auction for the Delivery Year. The Pool-wide average EFORd that is posted for the Third Incremental Auction for the Delivery Year is the final pool-wide average EFORd for the Delivery Year.

2.1.4 Forecast Pool Requirement

While IRM multiplied by peak load forecasts provides the installed capacity required to meet the reliability criterion, the Forecast Pool Requirement (FPR) multiplied by peak load forecasts provides unforced capacity values, required to meet the reliability criterion. Therefore, to express the Installed Reserve Margin (IRM) as an unforced capacity value, the calculation of the Forecast Pool Requirement must consider the forced outage rates of all generating units, or the Pool-wide Average EFORd.

The Forecast Pool Requirement is the measure determined for the specified Delivery Year to establish the level of unforced capacity (UCAP) that will provide an acceptable level of reliability consistent with PJM Reliability Principles and Standards.

The following parameters are values used in the determination of Forecast Pool Requirement:

- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd
- The Forecast Pool Requirement (FPR) for the Delivery Year is calculated by PJM and is equal to (1 + Installed Reserve Margin) times (1-Pool-wide Average EFORd).[1]

$$ForecastPoolRequirement\ (FPR) = (1 + InstalledReserveMargin) * (1 - PoolWideAverageEFORd)$$

The ***Forecast Pool Requirement (FPR)*** is approved by the PJM Board of Managers and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. An Updated FPR is approved by the PJM Board of Managers and posted one month prior to its use in an Incremental Auction for the Delivery Year. The Updated FPR that is posted for the Third Incremental Auction for the Delivery Year is the final FPR for the Delivery Year.

2.2 Role of Load Deliverability in the Reliability Pricing Model

The process of determining the Installed Reserve Margin (IRM) that meets the PJM reliability criterion assumes that the internal RTO transmission is adequate and any generation can be delivered to any load without transmission constraints. This process helps in determining the minimum possible IRM for the RTO. However, since transmission may have limitations, after IRM is determined a Load Deliverability analysis is conducted. The RTO is divided into different sub-regions for this analysis. These sub-regions are referred to as Locational Deliverability Areas (LDAs) in the Reliability Pricing Model.

The first step in the Load Deliverability analysis is to determine the transmission import capability required for each LDA to meet the area reliability criterion of Loss of Load Expectation of one occurrence in 25 years. This import capability requirement is called Capacity Emergency Transfer Objective (CETO), expressed in megawatts and valued as unforced capacity. The standard generation reliability evaluation model is used to determine CETO. For more details regarding the CETO analysis, please see ***Manual 20: Reserve Requirements.***

[1] The terms in this equation are expressed in decimal form.

The second step in Load Deliverability analysis is to determine the transmission import capability limit for each LDA using the transmission analysis models. For this analysis, a Transmission Upgrade including transmission facilities at voltages of 500 kV or higher that is in an approved Regional Transmission Expansion Plan ("Backbone Transmission") will be included in the system model only if it satisfies the project development milestones set forth in the tariff. This import capability limit is called Capacity Emergency Transfer Limit (CETL), expressed in megawatts and valued as unforced capacity. For more details regarding CETL analysis, please see ***Manual 14b: Generation and Transmission Interconnection Planning, Attachment B: PJM Deliverability Testing Methods.***

If CETL value is less than CETO value, transmission upgrades are planned under the Regional Transmission Expansion Planning Process (RTEPP). However, higher than anticipated load growth and unanticipated retirements may result in the CETL value being less than CETO value with no lead time to build transmission upgrades to increase CETL value. These conditions could result in locational constraints in the RTO.

2.3 Locational Constraints in the Reliability Pricing Model

When a capacity market does not have the ability to price capacity on a locational basis, all the resources in the market are valued equally throughout the RTO. When this occurs, it is possible to have excess reserves in the RTO and relatively low capacity prices. This market signal will result in generation capacity retirements. In some areas of the RTO these retirements will create reliability violations. These conditions will indicate that a higher value for resources is required to be recognized in constrained locations to incent existing generating capacity to remain in service, and new capability to be built in the form of generation resources, demand resources, or merchant transmission upgrades. One of the key features of RPM is the recognition of locational value of capacity.

Locational Constraints are localized capacity import capability limitations (low CETL margin over CETO) that are caused by transmission facility limitations or voltage limitations that are identified for a Delivery Year in the PJM Regional Transmission Expansion Planning Process (RTEPP) prior to each Base Residual Auction. Such Locational Constraints are included in the RPM to recognize and to quantify the locational value of capacity.

CETOs and CETLs for the LDAs to be modeled in all RPM Auctions for the Delivery Year are posted by February 1 prior to their use in the Base Residual Auction for the Delivery Year. Updated CETOs and CETLs for the modeled LDAs are posted one month prior to its use in an Incremental Auction for the Delivery Year.

2.3.1 Locational Deliverability Areas

In the development of the Reliability Pricing Model, the RTEP Process identified 25 sub-regions referred to as Locational Deliverability Areas for evaluating the locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

The 26 LDAs (highlighted in boldface) and an LDA's relationship to an immediate parent LDA are listed below:

RTO=> Western PJM

RTO => Western PJM => **ComEd**

RTO => Western PJM => **AEP**

RTO => Western PJM => **Dayton**

RTO => Western PJM => **DLCO**

RTO => Western PJM => **APS**

RTO => Western PJM => **ATSI**

RTO => Western PJM => **ATSI** => Cleveland

RTO => Western PJM => DEOK

RTO => Dominion

RTO => **MAAC**

RTO => MAAC => **WMAAC**

RTO => MAAC => WMAAC => **MetEd**

RTO => MAAC => WMAAC => **PPL**

RTO => MAAC => WMAAC => **Penelec**

RTO => MAAC => (includes RECO)

RTO => MAAC => EMAAC => **AE**

RTO => MAAC => EMAAC => **PSEG**

RTO => MAAC => EMAAC => PSEG => **PSEG N**

RTO => MAAC => EMAAC => **PECO**

RTO => MAAC => EMAAC => **JCPL**

RTO => MAAC => EMAAC => **DPL**

RTO => MAAC => EMAAC => DPL => **DPL S**

RTO => MAAC => **SWMAAC**

RTO => MAAC => SWMAAC => **BGE**

RTO => MAAC => SWMAAC => **PEPCO**

2.3.2 Constrained Locational Deliverability Areas (LDAs)

An LDA with Capacity Emergency Transfer Limit (CETL) less than 1.15 times Capacity Emergency Transfer Objective (CETO) will be modeled as a constrained LDA in RPM. In addition, an LDA will be modeled if (a) such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; (b) such LDA is determined by PJM to likely have a Locational Price Adder based on historic offer price levels; and (c) EMAAC, SWMAAC, and MAAC LDAs will be modeled as constrained LDAs regardless of the outcome of the above tests.[2] PJM may decide to model the LDA as a constrained LDA regardless of the outcome of the above tests if there are other reliability

[2] Prior to the 2012/2013 Delivery Year, an LDA with CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were considered in the modeling of a constrained LDA prior to the 2012/2013 Delivery Year.

concerns. A Reliability Requirement and a Variable Resource Requirement Curve will be established for each constrained LDA to be modeled in the RPM Base Residual Auction. See ***Section 5 of this Manual*** for the details. The constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year with their Reliability Requirements and the VRR Curves will be posted on the PJM website by February 1 prior to the commencement of the Base Residual Auction for that Delivery Year.

If an LDA clears with a Locational Price Adder in any Base Residual Auction, PJM shall perform an analysis to determine if any new generation, new demand resource or Qualifying Transmission Upgrades were cleared in that LDA in such Base Residual Auction. New generation or new demand resources include incremental upgrades to existing resources beyond historic installed capacity levels or new resource installations. If any LDA has a Locational Price Adder and if no new generation, new demand resource or Qualifying Transmission Upgrades have cleared in the LDA for two consecutive Base Residual Auctions, then PJM shall evaluate a transmission upgrade as part of the RTEPP that would reduce the Locational Price Adder to zero.

The evaluation of such transmission upgrade shall include an evaluation of the cost of the upgrade as compared to the incremental benefit of reducing Locational Price Adder to zero in the LDA. If the transmission upgrade is feasible and cost beneficial over the next ten year period, then the transmission upgrade shall be included in the Regional Transmission Expansion Plan as soon as possible. The annual costs of such upgrade shall be allocated to all LSEs serving load in the LDA, *pro rata* based on such loads.

2.3.3 Creation of New Locational Deliverability Areas (LDAs)

A prudent planning practice is to continuously monitor system performance and study transmission constraints as they develop. Triggers and criteria to consider a new LDA are specified in Manual 14B "PJM Regional Transmission Planning Process", Attachment B: PJM Deliverability Testing Methods, based on RTEP Market Efficiency Analysis and RTEP Long Term Planning. PJM will make a filing with FERC to amend RAA Schedule 10.1 to add a new LDA (including a new LDA that is an aggregate of Zones), if such new area is projected to have a CETL less than 1.15[3] times the CETO of the area, or if warranted by other reliability concern. In addition, any Party may propose, and PJM would evaluate, possible LDAs under such standards.

2.4 Reliability Requirements

In the PJM Capacity Market, reliability requirements, or reserve requirements, represent the target level of reserves required to meet PJM Reliability Standards and Principles. It is important to note that the Installed Reserve Margin (IRM) and the Forecast Pool Requirement (FPR) represent the level of reserves required, but are expressed in different capacity values. The IRM is expressed as the <u>installed capacity</u> reserve as a percent (e.g. 15%) of the forecast peak load, whereas the FPR (e.g., 1.079) when multiplied by forecast peak load provides of the total <u>unforced capacity</u> required. The installed capacity (ICAP) value of a generation resource is based on the summer net dependable rating of a unit as determined in accordance with PJM's Rules and Procedures, also referred to as "Iron in the Ground". The unforced capacity (UCAP) value of a generation resource is installed capacity

[3] Prior to the 2012/2013 Delivery Year, the CETL/CETO threshold was 1.05.

rated at summer conditions that is not on average experiencing a forced outage or forced de-rating.

In the RPM clearing process, the Reliability Requirements for the RTO and the LDA are used to establish the target reserve levels, valued as unforced capacity that will be cleared in the RPM Auctions.

The final Reliability Requirements, used in the clearing of RPM Auctions, will be adjusted to account for entities that have elected the Fixed Resource Requirement Alternative. Therefore, when known, the Unforced Capacity Obligations for FRR entities will be removed from the calculation of the Reliability Requirements for the RTO and any LDAs. Reliability Requirements for the region and for any affected LDA are further adjusted for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

2.4.1 PJM Region Reliability Requirement

The PJM Region Reliability Requirement, valued in unforced capacity terms, is the RTO Peak Load Forecast, multiplied by the approved Forecast Pool Requirement for the PJM Region, less the sum of Preliminary Unforced Capacity Obligations of the FRR Entities in the PJM Region, and less any necessary adjustment for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

$$RelReq_{\mathrm{PJMRegion}} = (RTOPeakLoadForecast) \times (FPR) - \sum PrelimUnforcedCapObligations_{\mathrm{FRREntities}}$$

2.4.2 Reliability Requirement in Locational Deliverability Areas

The Locational Deliverability Area Reliability Requirement is the projected internal capacity (in UCAP terms) in the LDA plus the Capacity Emergency Transfer Objective (CETO) for the Delivery Year, as determined by the RTEP process, less the minimum internal resources (in UCAP terms) required for the FRR Entities located in the LDA, and less any necessary adjustment for PRD proposed in an approved PRD Plan or committed in any RPM Auction for PRD located in the LDA.

$$RelReq_{\mathrm{LDA}} = ProjectedInternalCap + CETO - (\mathrm{Min}\,Internal\ Resources_{\mathrm{FRREntities}})$$

2.4.3 Minimum Annual/Extended Summer Resource Requirements

Starting with the 2014/2015 Delivery Year, two additional demand resource products have been established - one available throughout the year (Annual DR) and another available for an extended summer period (Extended Summer DR). These new products have fewer limitations than the Limited Demand Resource product (Limited DR). New auction rules effective with the 2014/2015 BRA recognize the greater reliability value associated with less limited resources by establishing and enforcing a minimum requirement on the commitment of less limited products. The Minimum Annual Resource Requirement is the minimum amount of capacity sought to be procured in each auction from Annual Resources (Annual Resources include generation capacity resources, energy efficiency resources and annual demand resources). The Minimum Extended Summer Resource Requirement is the minimum amount of capacity sought to be procured in each auction from Extended Summer Demand Resources and Annual Resources.

Minimum Annual and Minimum Extended Summer Resource Requirements are established for the RTO and each modeled LDA and the auction clearing process can select Extended

Summer DR or Annual Resources out of merit order, if necessary, to procure the minimum required quantities, similar to the way in which RPM auctions can select resources out of merit order to address locational constraints. In those cases where one or both of the minimum resource requirements do bind in the auction solution, just as with resources selected to resolve locational constraints, resources selected to meet the necessary minimum resource requirements will receive an adder to the system marginal price of capacity (in addition to any locational price adder(s) received to resolve locational constraints).

For the RTO, the Minimum Annual Resource Requirement is equal to the RTO Reliability Requirement minus [the Extended Summer Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement is equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Extended Summer Demand Resource Reliability Target for the LDA in Unforced Capacity]. The LDA CETL may be adjusted pro-rata for the amount of load in the LDA served under the FRR Alternative. The Extended Summer Demand Resource Reliability Target for the PJM Region or an LDA is the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability as more fully described in the ***PJM Manual for Reserve Requirements (M-20).***

For the RTO, the Minimum Extended Summer Resource Requirement is equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement is equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for the LDA in Unforced Capacity]. The LDA CETL may be adjusted pro-rata for the amount of load in the LDA served under the FRR Alternative. The Limited Demand Resource Reliability Target for the PJM Region or an LDA is the maximum amount of Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability as more fully described in the ***PJM Manual for Reserve Requirements (M-20)***.

2.4.4 Adjustments to RPM Auction Parameters for PRD

After PRD Providers propose PRD commitments in their PRD Plans, and PJM reviews and accepts those commitments, PJM will use the resulting PRD values to reduce the reliability requirement to be satisfied for the region and for any affected Zones (or sub-Zonal LDAs). The reliability requirement will be reduced by the quantity of UCAP that would have been procured on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The Reliability Requirement of the RTO and each affected LDA will be reduced by a quantity equal to the Nominal PRD Value multiplied by the FPR. These reliability requirement reductions will be considered in the development of the RTO/LDA Variable Resource Requirement Curves, RTO/LDA Minimum Annual Resource Requirements, and RTO/LDA Minimum Extended Summer Resource Requirements.

Section 3: Demand in the Reliability Pricing Model

Welcome to the Demand in the Reliability Pricing Model section of the PJM Capacity Market Manual. In this section, you will find the following information:

- An overview description of demand in the Reliability Pricing Model (see "Overview of Demand in the Reliability Pricing Model")
- The definition and purpose of the Variable Resource Requirement
- The method for plotting the Variable Resource Requirement Curve (see "Plotting the Variable Resource Requirement Curve")
- A description of the demand curves in the Incremental Auctions (see "Demand Curves in the Incremental Auction")

3.1 Overview of Demand in the Reliability Pricing Model

In the Reliability Pricing Model, the demand for installed capacity reserve is met when supply is procured as a function of the clearing of the RPM Auctions. A demand curve is defined in advance of each RPM Auction.

In the Base Residual Auction, the demand curve is downward sloping and based on the variable resource requirement concept. In RPM, a variable resource requirement is defined as a function of price. The variable resource requirement is a family of price/quantity points that provide a specified price for various levels of resources procured relative to the Installed Reserve Margin. If the price exceeds the limit on the VRR, then the quantity of resources that is procured may be less than the IRM requirement. Alternatively, if the price is low, additional resources may be procured at a level greater than the IRM requirement. The cost of the supply that is procured at the clearing price will be allocated to the Load Serving Entities. Therefore, a variable resource requirement curve will reflect the reality that additional capacity above a target installed reserve margin nevertheless has value.

There are at least four sources of this value:

(1) One source of value is that in the face of uncertain load growth, weather and capacity availability, the probability of available capacity being less than what is required to meet load and operating reserves never reaches zero, even for large reserve margins. Thus, reserves beyond the target are valuable for reducing the risk of capacity shortfalls.

(2) The second source of value is that the slope of the curve can lessen the risk of large suppliers being pivotal or otherwise able to exercise market power.

(3) A third source of value is that excess resources can reduce the frequency and duration of scarcity energy prices in the system and provide energy savings to Load Serving Entities.

(4) The fourth source of value is the reduction in capacity price volatility and the resulting investment risk to capacity resources, in particular to the generating resources. Lower investment costs would tend to reduce capacity prices

3.2 Definition and Purpose of the Variable Resource Requirement

As mentioned in the previous section, the Variable Resource Requirement Curve is a demand curve used in the clearing of the Base Residual Auction that defines the price for a given level of Capacity Resource commitment relative to the applicable reliability requirement. Variable Resource Requirement Curves are defined for the PJM Region and each of the constrained LDAs within the PJM region.

The purpose of the Variable Resource Requirement concept is to recognize the value of excess resources above the reliability requirement and provide revenue to resources. The price on the Variable Resource Requirement is higher when the resources are less than the reliability requirement and lower when the resources are in excess.

3.3 Parameters of the Variable Resource Requirement

Prior to the clearing of the Base Residual Auction, Variable Resource Requirement Curves are defined for the PJM Region and each of the constrained Locational Delivery Areas (LDA) within the PJM region. The Variable Resource Requirement Curves for the PJM Region and each Locational Delivery Area (LDA) are based on the following parameters defined prior to the RPM Auctions:

- A target level of reserve
- Cost of New Entry
- Net Energy & Ancillary Services (E&AS) Revenue Offset
- The Nominal PRD Value and PRD Reservation Prices that have been elected

The initial posting of the Variable Resource Requirement Curves will be based on the adjustments related to FRR Entities' Preliminary Unforced Capacity Obligations known at the time of posting. A later posting of the Variable Resource Requirement Curves with the FRR adjustments will be made shortly after the approval of the FRR Capacity Plans for the RPM Auction Delivery Year considering any changes in the FRR elections.

The parameters of the Variable Resource Requirement Curve (i.e., RTO and LDA Reliability Requirements, Cost of New Entry, and Net E&AS Revenue Offsets) will be posted by **February 1** prior to the conduct of the Base Residual Auction for the Delivery Year.

The Variable Resource Requirement Curve for the PJM Region is based on a target level (i.e., the PJM Region Reliability Requirement less the Short Term Resource Procurement Target), Cost of New Entry, and Net Energy & Ancillary Services (E&AS) Revenue Offset.

For each LDA, the LDA Variable Resource Requirement Curve is based on a target level (i.e., the LDA Reliability Requirement less the LDA Short Term Resource Procurement Target), Cost of New Entry, and Net E&AS Revenue Offset.

Inclusion of Variable Resource Requirement Curves in the Base Residual Auction clearing may result in the level of resources being committed for a Delivery Year exceeding the applicable PJM Region Reliability Requirement less the Short Term Resource Procurement Target or the LDA Reliability Requirement less the LDA Short Term Resource Procurement Target, if the total cost of resource procurement for the PJM Region or LDA is lower at the higher level of reliability than it would be at the target level and the associated Variable Resource Requirement Curve price.

3.3.1 Cost of New Entry

The value for Cost of New Entry (in ICAP terms) is determined in accordance with the Open Access Transmission Tariff. There may be different values for the Cost of New Entry for different Locational Deliverability Areas. The Cost of New Entry values are posted in the Tariff. (See Tariff Section 5.10, (iv),(A)) The Cost of New Entry for a Locational Deliverability Area shall be determined based upon the geographic location of the Locational Deliverability Area within the PJM Region. A Cost of New Entry is determined for each of the following five combinations of zones (if the LDA covers more than one of these five sub-regions, the lowest Cost of New Entry is used for defining the LDA's VRR curve) referred to as CONE Areas:

1. AE, DPL, JCPL, PECO, PSEG, RECO;
2. BGE, PEPCO
3. AEP, APS, COMED, DAYTON, DLCo, ATSI, DEOK;
4. METED, PENELEC, PPL; and
5. Dominion

The CONE values to be posted with the Planning Parameters for BRA will be escalated using the most recently published twelve-month change in Total Other Plant Production Plant Index shown in the Handy Whitman Index (HWI) of Public Utility Construction Costs. The North Atlantic Region HWI will be used for CONE Areas 1, 2, and 4. The North Central Region HWI will be used for CONE Area 3. The South Atlantic Region HWI will be used for CONE Area 5.

The value of Cost of New Entry used in the development of the RTO VRR Curve and the VRR Curve for each modeled LDA is expressed in UCAP Terms.

3.3.2 Net Energy and Ancillary Services Offset

The Net Energy & Ancillary Services (E&AS) Revenue Offsets for PJM Region and each modeled LDA (in ICAP Terms) is determined by PJM using the Peak-Hour Dispatch in accordance with the **Open Access Transmission Tariff, Section 5.10, (v).**

The Net E&AS Revenue Offset is based on the three most recent calendar years of Energy & Ancillary Services revenue for a reference combustion turbine.

The value of Net E&AS Revenue Offset used in the development of the RTO VRR Curve and the VRR Curve for each modeled LDA is expressed in UCAP Terms.

3.4 Plotting the Variable Resource Requirement Curve

The Variable Resource Requirement Curve is plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis using the following three points (a), (b), and (c):

a. The price is equal to the greater of [the Cost of New Entry or 1.5 times (the Cost of New Entry minus the Net E&AS Revenue Offset, referred to as "Net CONE")] divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity is equal to [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% minus 3%) divided by (100% plus approved IRM %)] minus the RTO Short-Term Resource Procurement Target

Basis for Price at Point a:

$$\frac{Greaterof[CONEor1.5(CONE - E\ \&\ AS)]}{1 - Pool\ \ Wide\ \ EFORd}$$

Basis for Quantity at Point a:

$$\left[\mathrm{Rel\,Req}\frac{(100\% + IRM - 3\%)}{(100\% + IRM)}\right] - \begin{matrix}\text{Short - Term Resource}\\ \text{Procurement Target}\end{matrix}$$

b. The price is equal to Net CONE divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 1%) divided by (100% plus approved IRM%)] minus the RTO Short-Term Resource Procurement Target.

Basis for Price at Point b:

$$\frac{[1.0(CONE - E\,\&\,AS)]}{1 - Pool\ Wide\ EFORd}$$

Basis for Quantity at Point b:

$$\left[\mathrm{Rel\,Req}\frac{(100\% + IRM + 1\%)}{(100\% + IRM)}\right] - \begin{matrix}\text{Short - Term Resource}\\ \text{Procurement Target}\end{matrix}$$

c. The price is equal to 0.2 times the Net CONE divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 5%) divided by (100% plus approved IRM %) minus the RTO Short-Term Resource Procurement Target.

Basis for Price at Point c:

$$\frac{[0.2(CONE - E\,\&\,AS)]}{1 - Pool\ Wide\ EFORd}$$

Basis for Quantity at Point c:

$$\left[\mathrm{Rel\,Req}\frac{(100\% + IRM + 5\%)}{(100\% + IRM)}\right] - \begin{matrix}\text{Short - Term Resource}\\ \text{Procurement Target}\end{matrix}$$

3.4.1 Plotting the Variable Resource Requirement Curves

The graph below illustrates the process for plotting the Variable Resource Requirement curves:

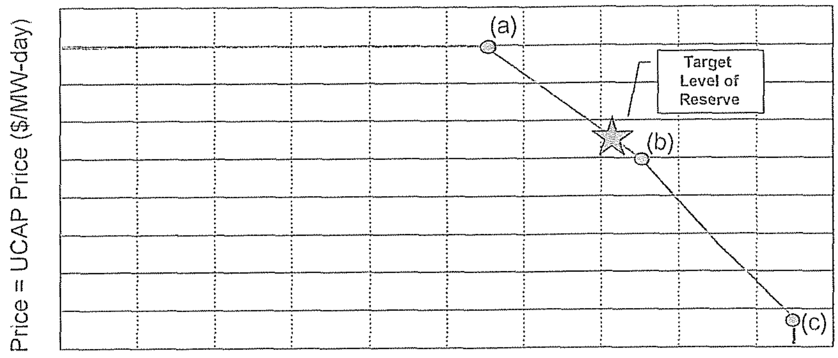

Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve

The same process shall be used to establish the Variable Resource Requirement Curve for each LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement, and the LDA Short-Term Resource Procurement Target for the Zones associated with such LDA shall be substituted for the RTO Short-Term Resource Procurement Target and the FRR adjustments will be for the FRR Entities in the LDA.

In 2014, PJM will perform a review of the shape of the Variable Resource Requirement Curve, CONE values, and Energy & Ancillary Services methodology, and any changes resulting from this review will be incorporated into the BRA that is conducted in May 2015 for the 2018/2019 Delivery Year. Such a review will be conducted again in 2018 and every fourth year thereafter.

The Variable Resource Requirement Curve of Exhibit 1 will be further adjusted to reflect the impact of any PRD that is proposed in a PRD Plan and that is reviewed and accepted by PJM. To reflect accepted PRD Plans, the Variable Resource Requirement Curve will be shifted leftward along the horizontal axis by a quantity equal to the Nominal PRD Value multiplied by the FPR. This quantity represents the quantity of Unforced Capacity that would have been procured in the RTO on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The curve will be shifted leftward in this manner only for those portions of the curve that are at or above the PRD Reservation Price, since the PRD load can be excluded only if the auction clears at or above that price. The Variable Resource Requirement Curve for each LDA in which the PRD resides (including the RTO curve) will be shifted in the exact same manner.

3.5 Demand Curves in the Incremental Auctions

The First, Second and Third Incremental Auctions provide both a forum for capacity suppliers to purchase replacement capacity, and a means for PJM to adjust previously committed capacity levels due to reliability requirement increases or decreases and to recoup the appropriate share of the deferred Short-Term Resource Procurement Target. The demand curve in these auctions will be built based on a combination of buy bids submitted by market participants and buy bids, if any, submitted by PJM.

PJM will recalculate the RTO and each LDA Reliability Requirement prior to each of the First, Second, and Third Incremental Auctions based on an updated peak load forecast, updated Installed Reserve Margin, and an updated Capacity Emergency Transfer Objective. The recalculated Reliability Requirements are compared to the Reliability Requirements used in the prior auction for the same Delivery Year and a determination is made as to the need for the procurement and/or sale of capacity by PJM.

For the RTO and each LDA, PJM will sum the following component quantities to determine the total quantity that it will seek to procure or release in each Incremental Auction:

- The Short-Term Resource Procurement Target Applicable Share (STRPTAS). For a 1st or 2nd Incremental Auction, the STRPTAS is equal to 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction (BRA). For a 3rd Incremental Auction, the STRPTAS is equal to 0.6 times the Short-Term Resource Procurement Target used in the Base Residual Auction (BRA),
- Plus the difference between the Updated Reliability Requirement minus the Reliability Requirement utilized in the most recent prior auction conducted for that Delivery Year. For a 1st or 2nd Incremental Auction, this difference is only considered if the change in Reliability Requirement is greater than the lesser of 500 MW or 1% of the prior auction's Reliability Requirement. Note that this quantity is negative if the Updated Reliability Requirement is less than the Reliability Requirement utilized in the most recent prior auction.
- Plus/minus the amount of committed capacity that PJM sought to procure/release that did not clear in previous Incremental Auctions for the same Delivery Year.
- Minus any capacity PJM seeks to release in a parent LDA as a result of any Conditional Incremental Auction commitments for the same Delivery Year.

If the result of such summation is a positive quantity, PJM will seek to procure such quantity by employing a PJM buy bid represented by the portion of the Updated VRR Curve Increment extending right from the left-most portion on that curve in a MW amount equal to the positive quantity. PJM will employ a PJM buy bid represented by the entire portion of the Updated VRR Curve if the prior auction's RTO/LDA Reliability Requirement less Short-Term Resource Procurement Target exceeds the total capacity committed in all prior auction's by the threshold (lesser of 500 MW or 1% of prior auction's Reliability Requirement). The Updated VRR Curve Increment is the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

If the result of such summation is a negative quantity, PJM will seek to release such quantity by employing a PJM sell offer represented by the portion of the Updated VRR Curve

Decrement extending and ascending to the left from the right-most portion on that curve in a MW amount equal to the negative quantity. The Updated VRR Curve Decrement is the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

Starting with the 2014/2015 Delivery Year, prior to each Incremental Auction, PJM will calculate an updated Minimum Annual Resource Requirement and a Minimum Extended Summer Resource Requirement for the RTO and each LDA. The difference between the updated Minimum Annual Resource Requirement minus the amount of previously procured capacity from Annual Resources will determine the portion of a PJM buy bid that must be satisfied by Annual Resources. If PJM is seeking to release capacity in the auction, this difference will determine the maximum amount of Annual Resources that PJM is willing to release. The difference between the Minimum Extended Summer Resource Requirement minus the combined total amount of previously procured Annual Resource and Extended Summer Demand Resources will determine the portion of a PJM buy bid that must be satisfied by Annual Resources and Extended Summer DR. If PJM is seeking to release capacity in the auction, this difference will determine the maximum amount of Annual Resources and Extended Summer DR that PJM is willing to release.

In a Conditional Incremental Auction, the quantity at the appropriate location required to address the identified reliability violation will be procured using a Buy Bid equal to 1.5 times Net CONE.

Section 3A: Integration of Price Responsive Demand

Welcome to the Integration of Price Responsive Demand section of the PJM Manual for the PJM Capacity Market. In this section, you will find the following information:

- An overview of Price Responsive Demand in PJM Capacity Market (see "Overview of Price Responsive Demand in PJM Capacity Market")
- The transition period for price responsive demand (see "Transition Period")
- The eligibility requirements for price responsive demand participation in PJM Capacity Market (see "Eligibility Requirements for Price Responsive Demand")
- The PRD Plan requirements (see "PRD Plan Requirements")

3A.1 Overview of Price Responsive Demand in PJM Capacity Market

The development and implementation of dynamic and time-differentiated retail rates, together with utility investment in advanced metering infrastructure (AMI) has lead an increasing quantity of load in PJM to be responsive to changing wholesale prices. Through enabling technology and behavioral changes, consumers modify their demand as prices change without being centrally dispatched by PJM or bidding demand reductions into the PJM markets. Given the linkage between dynamic retail rate structures and wholesale prices, this price responsiveness is predictable and needs to be accounted for in the wholesale market design and operations. This predictable reduction in consumption in response to changing wholesale prices is known as Price Responsive Demand (PRD).

Although Price Responsive Demand is not directly dispatchable by PJM, automated retail customer response to real time energy prices signals can produce a predictable demand curve as a function of real time energy price. Prices typically increase during capacity emergencies and as a consequence demand drops. Price Responsive Demand will therefore be able to reduce the installed capacity required to meet Loss of Load Expectation (LOLE) based reliability standards.

PRD is provided by a PJM Member that represents retail customers that have the capability to reduce load in response to price. PJM Member acting on behalf of such retail customers for the purpose of providing PRD is referred to as the PRD Provider. A PRD Provider for a given retail customer may be the customer's retail Load Serving Entity (LSE). However, PRD may also be provided in the PJM markets by an entity such as an Electric Distribution Company (EDC), or Curtailment Service Provider (CSP) that does not have direct responsibility for serving the retail load but meets all of the eligibility requirements for providing PRD.

In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of Price Responsive Demand that will reduce its consumption in response to real time energy price during a Delivery Year.

In order to commit PRD for a Delivery Year, a PRD Provider must submit a PRD Plan in advance of the Base Residual Auction or Third Incremental Auction for such Delivery Year that demonstrates to PJM's satisfaction that the maximum nominated amount of price responsive demand will be available by the start of the Delivery Year. Additional PRD may participate in the Third Incremental Auction only in the event, and to the extent that the LDA final peak load forecast for the Delivery Year increases relative to the LDA preliminary peak load forecast used for the Base Residual Auction.

A PRD Provider that is committing PRD in Base Residual Auction or Third Incremental Auction must also submit a PRD election in the eRPM system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The PRD election by PRD Providers will result in a change in the shape of the RTO/LDA VRR Curves used in the RPM Auctions. Based on the PRD elections and Resource Clearing Price in the RPM Auction, PJM will determine the Nominal PRD Value committed by each PRD Provider. Those PRD Providers that elected to provide PRD at reservation prices equal to or less than the Resource Clearing Price will have the corresponding value of PRD committed in the RPM Auction.

A PRD Provider that is committing PRD which is associated with load being served under the Fixed Resource Requirement Alternative is not required to submit a PRD election. The FRR Entity's Preliminary Daily Unforced Capacity Obligation to be satisfied in the FRR Entity's initial submittal of their FRR Capacity Plan for the Delivery Year will be reduced by the Nominal PRD Value associated with their FRR load that was approved by PJM in advance of the BRA, multiplied by the BRA Forecast Pool Requirement. The Final Daily Unforced Capacity Obligation of the FRR Entity that must be satisfied in the FRR Entity's FRR Capacity Plan for the Delivery Year will be reduced by the total Nominal PRD Value associated with their FRR load that was approved by PJM in advance of the Base Residual Auction and Third Incremental Auction for the Delivery Year, multiplied by the final Forecast Pool Requirement. The approval of the PRD Provider's PRD Plan associated with the FRR load shall establish a firm commitment of the PRD Provider to the PJM approved sub-zonal/zonal Nominal PRD Value.

Once committed in a Base Residual Auction, Third Incremental Auction or committed for load served under the FRR Alternative, Price Responsive Demand may not be uncommitted or replaced by available capacity resources or Excess Commitment Credits. However, a PRD Provider may transfer the PRD obligation to another PRD Provider bilaterally.

A PRD Provider with a committed sub-zonal/zonal Nominal PRD Value through an RPM Auction or through the FRR Alternative will be required to register sub-zonal/zonal PRD prior to the start of the Delivery Year to satisfy their PRD commitment. Failure to register enough price responsive loads to meet their sub-zonal/zonal PRD commitment prior to the start of the Delivery Year or failure to maintain enough price responsive loads to meet their sub-zonal/zonal PRD commitment throughout the Delivery Year will result in a PRD Commitment Compliance Penalty.

A PRD Provider will also be subject to performance compliance during Maximum Emergency Events during the Delivery Year. Failure to comply during Maximum Emergency Events will result in a PRD Maximum Emergency Event Compliance Penalty. If PJM does not declare a Maximum Generation Emergency during the Delivery Year that requires the zonal PRD to reduce to the zonal MESL, then the zonal registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency Event may be called during June through October or the following May of the relevant Delivery Year. Failure of the zonal registered PRD to reduce to the zonal MESL in a test will result in a PRD Test Failure Charge.

An LSE serving PRD in RPM registered by a PRD Provider will receive a Daily PRD Credit ($/MW-day) during the Delivery Year. The Daily PRD Credit may offset the Daily Locational

Reliability Charges ($/day) that are assessed to the LSE serving such PRD during the Delivery Year. A FRR Entity serving PRD under the FRR Alternative will not be eligible to receive a Daily PRD Credit ($/MW-day) during the Delivery Year.

3A. 2 Transition Period

The maximum quantity of PRD that can be committed in the RTO through RPM Auctions for a Delivery Year is capped during the transition period (2016/2017 – 2018/2019) Delivery Years) as follows:

2016/2017 Delivery Year	2017/2018 Delivery Year	2018/2019 Delivery Year	2019/2020 Delivery Year & future Delivery Years
2,500 MW	3,500 MW	4,000 MW	No Cap

Although there is a limit on the amount of PRD that may be committed to PJM through RPM Auctions during the transition period, there is no limit on the amount of PRD that can be reflected in the Day-ahead and Real-time Energy Markets.

PRD will be committed in the Base Residual Auction based on the most economical BRA PRD elections. If, as a result of the initial clearing of the BRA, the total PRD commitments exceed the RTO cap for the transition Delivery Year, PJM will ensure that the total PRD commitments in a zone (or sub-zonal LDA) do not exceed a zonal (or sub-zonal LDA) allocation of the RTO cap. The RTO cap is allocated to the zones (or sub-zonal LDA) pro-rata based on the Preliminary Zonal (or Sub-Zonal LDA) Peak Load Forecast less zonal (or sub-zonal LDA) forecasted peak load to be served under the FRR Alternative. Unused portions of a zonal (or sub-zonal LDA) allocation will be assigned to other zones (or sub-zonal LDAs) in which the initial PRD committed amount exceeded the zonal (or sub-zonal) allocation. Such assignments will be based on committing the most economical BRA PRD elections in such other zones (or sub-zonal LDAs).

PRD will be committed in the Third Incremental Auction based on the most economical Third IA PRD elections. If, as a result of the initial clearing of the Third IA, the total PRD commitments in the BRA and Third IA exceed the RTO cap for the transition Delivery Year, PJM will ensure that the total BRA and Third IA PRD commitments in a zone (or sub-zonal LDA) do not exceed a zonal (or sub-zonal LDA) allocation of the RTO cap. The RTO cap is allocated to the zones (or sub-zonal LDA) pro-rata based on the Preliminary Zonal (or Sub-Zonal LDA) Peak Load Forecast less zonal (or sub-zonal LDA) forecasted peak load to be served under the FRR Alternative. Unused portions of a zonal (or sub-zonal LDA) allocation will be assigned to other zones (or sub-zonal LDAs) in which the initial total (BRA and Third IA) PRD committed amount exceeded the zonal (or sub-zonal) allocation. Such assignments will be based on committing the most economical Third IA PRD elections in such other zones (or sub-zonal LDAs).

During the transition period, annual reviews will be conducted to inform the market of the impact of Price Responsive Demand.

3A.3 Eligibility Requirements of Price Responsive Demand

In order for load to be eligible to be considered as Price Responsive Demand, the end-use customer load must be:

- served under a dynamic retail rate structure with an LSE or subject to a contractual arrangement with a PRD Provider where such rate or compensation arrangement can change on an hourly basis, is linked to or based upon a PJM real-time LMP trigger at a substation location within a transmission zone as electrically close as practical to the applicable load, and results in predictable response to varying wholesale electricity prices;
- subject to advanced metering capable of recording electricity consumption at an interval of one hour or less; and
- subject to Supervisory Control as defined in the Reliability Assurance Agreement to curtail the demand should PJM declare an emergency condition.

Supervisory Control of customer load registered as Price Responsive Demand is required on the part of the PRD Provider consistent with any Relevant Electric Retail Regulatory Authority (RERRA) requirements. RERRA shall have the meaning specified in the PJM Operating Agreement. To the extent load was not already reduced, the PRD Provider is required to have the remote capability to decrease the load at each location contained in the PRD Registration to the required service level when a PJM Maximum Emergency event has been declared and the LMP at the applicable location has exceeded the level at which the load has committed to reduce. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to Real Time LMPs for the PRD Curves that are submitted in the PJM Energy Market. Automation of load response to LMP trigger without manual intervention is required to be PRD.

However, PRD Providers may request an exception to the automation requirement for end-use customers that are a single site, a single location and a single end-use customer with supervisory control over processes with which load reduction would be accomplished. In this case, the end use customer site is eligible for this specific exception from standard automation requirement, but the end-use customer is still required to respond within 15 minutes to Real Time LMPs for the PRD Curves that are submitted in the PJM Energy Market.

The customer load must be on a dynamic retail rate structure with an LSE or subject to a contractual arrangement with a PRD Provider that results in retail charges or credits to the end use customer that are linked to or based on the Real Time LMP. Multiple retail rates or contractual arrangements could qualify for this requirement, such as a structure where the retail charge or credit to the end-use customer is greater than or equal to the Real-time LMP, or applies only when the Real Time LMP exceeds a preset threshold. Dynamic retail rate structures, based on PJM Real-time LMP, that qualify as Price Responsive Demand may include:

- Critical Peak Pricing that allows retail rates to rise when the wholesale market price exceeds a threshold level;
- Critical Peak Rebate pricing which provides bill credits to consumers who reduce their usage below a baseline quantity during periods when the wholesale market price exceeds a threshold level; or

- Real-Time Pricing based on LMP.

3A.4 PRD Plan Requirements

3A.4.1 PRD Plan Submission & Approval Process

A PRD Provider that wishes to nominate PRD load for a Delivery Year's Base Residual Auction or nominate PRD to reduce an FRR Entity's preliminary unforced capacity obligation must submit a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 immediately prior to the Delivery Year's Base Residual Auction. Additional PRD may be nominated in an LDA in the Third Incremental Auction in the event and to the extent that the LDA final peak load forecast used in Third Incremental Auction increases relative to LDA preliminary peak load forecast used in the Base Residual Auction. Nomination of additional PRD load in an LDA for a Delivery Year's Third Incremental Auction when LDA peak load forecast increases may be made by submitting a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 immediately prior to the Delivery Year's Third Incremental Auction. Nomination of additional PRD for use in reducing an FRR Entity's final unforced capacity obligation for the Delivery Year may also be made by submitting a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 prior to the Delivery Year's Third Incremental Auction.

Once received by PJM, the PRD Provider will receive an email confirmation that their plan has been received and will be reviewed by PJM. PJM will review the content to ensure the PRD Plan contains all the necessary detail and information. PJM will notify the PRD Provider within 10 days of receipt of the PRD Plan and indicate whether or not the PRD Plan is approved or rejected. Any submitted plan that is incomplete or falls short of meeting the informational requirements of a PRD Plan by such January 15 deadline shall be rejected.

A PRD Provider must submit a PRD Plan no later than January 1, prior to a Base Residual Auction or Third Incremental Auction if the PRD Provider wants PJM to conduct an advance review of their PRD Plan. PJM will review the content of the PRD Plan and will notify the PRD Provider within 10 days of receipt of the PRD Plan if the submitted PRD Plan is approved or rejected. If the PRD Plan is rejected, PJM will provide to the PRD Provider a list of the areas in the PRD Plan that were not adequate. PRD Plans that are denied by PJM in an advance review may be corrected and resubmitted no later than January 15, prior to the Base Residual Auction or Third Incremental Action. Alternately, PJM may approve a lower maximum Nominal PRD Value supported by the PRD Plan.

To help a PRD Provider prepare and submit a PRD Plan by the January 15 deadline, the following information will be made available:

- Prior year summer weather normalized zonal peak loads posted by PJM by October 31. The summer weather normalized zonal peak loads will be developed from hourly metered zonal loads that include add backs due to demand response and price responsive demand in accordance with PJM Manual 19, Load Forecasting and Analysis.
- Customer PLCs developed and made available by EDCs based on prior year summer weather normalized Zonal peak loads by December 31.
- Zonal Scaling Factors (Ratio of Delivery Year Zonal Peak Load Forecast to prior year summer weather normalized Zonal peak load) posted by PJM by January first week.

3A.4.2 Required Components of a PRD Plan

The PRD Plan is a document submitted by the PRD Provider that defines and provides data to support a PRD Provider's maximum Nominal PRD Value in a Zone or sub-zone LDA (for example, if nominating PRD in DPL South or PS North). The PRD plan must identify any methods and techniques that will be used to determine and verify the quantity of load consumed at varying wholesale price levels. A single PRD Plan may be submitted to cover multiple Sub-zone/Zone locations, provided that the price-demand curves are submitted on a Sub-zone/Zone level. All of the assumptions, procedures, and data for the PRD Plan should be clearly documented. The data included should be sufficient for a third party to audit the procedures and verify the PRD Provider's maximum Nominal PRD Value in a Sub-zone/Zone.

The PRD Plan must detail the price responsive characteristic of the customer load at a zonal or sub-zonal LDA (for example, if load is in PSEG-North or DPL-South) level. If known, the PRD Plan should detail the price responsive characteristics at a substation level. The price responsive characteristic of such customer loads must be provided in terms of the quantity of load that will continue to consume at various levels of price.

The Expected Peak Load Value of PRD is the expected contribution of such PRD Provider's price responsive load to the Delivery Year's Zonal Peak Load Forecast if such load were not to be reduced in response to price. The substation/sub-zonal/zonal Expected Peak Load Values of PRD will be aggregated to determine the Zonal/LDA I Expected Peak Load Value of PRD quantity for the PRD Provider in such Zone/LDA.

The Maximum Emergency Service Level (MESL) is the level to which the price-responsive load will be reduced during the Delivery Year when a Maximum Emergency Event is declared. The quantity of load that will be consumed at a price equal to the applicable energy market offer cap to the relevant delivery year represents the MESL. The locational MESL quantities (at substation/sub-zonal/zonal) will be aggregated to determine the Zone/LDA MESL quantity for the PRD Provider in such Zone/LDA.

For the purposes of the PRD Plan, the PRD Provider's Nominal PRD Value for a Zone/LDA is the difference between the PRD Provider's Zonal/LDA Expected Peak Load Value of PRD and MESL for such Zone/LDA.

A Price Responsive Demand (PRD) Plan submitted to PJM must include:

- Company name
- Submission date
- Company address and contact information
- Indication of whether price responsive demand is being nominated for an RPM Auction or for use in reducing an FRR Entity's unforced capacity obligation
- Location of Price Responsive Demand by applicable electrical location within a transmission zone (i.e., PNODE), if available at the time of submittal of PRD Plan, or by Sub-zone/Zone. At the time of the submittal of PRD Plan, the PRD Provider may provide data at the smallest LDA level, but the PRD Provider is required to provide final locational detail (i.e., PNODE) prior to Delivery Year.
- Expected Peak Load Value of PRD by applicable electrical location, if available, or by Sub-zone/Zone

- Maximum Emergency Service Level (MESL) of Price Responsive Demand by applicable electrical location, if available, or by Sub-zone/Zone
- Nominal PRD Value by applicable electrical location, if available, or by Sub-zone/Zone. The smallest increment that may be submitted for a Sub-zone/Zone is .1 MW.
- PRD Reservation Price, elected by PRD Provider as defined in section 3A.4.2.3
- Price-Demand curves at the applicable electrical location, (PNODE)/Sub-zone/Zone level, detailing the base electricity consumption level as well as the decreasing consumption levels (i.e., demand levels) at increasing wholesale energy prices (i.e., real-time LMPs).
- A description of the methodologies, analysis, or pilot programs used to determine the Expected Peak Load Value of PRD, Maximum Emergency Service Level (MESL) value, and Price-Demand Curves
- Specifications of the equipment used to meet the advanced metering and supervisory control requirements, including a project plan and timeline with the milestones that demonstrates that the AMI and supervisory control will be available and operational for the start of the Delivery Year.
- If the PRD Provider is an LSE, documentation, conforming to ***Section 3A.4.2.2*** below, verifying that the LSE has Relevant Electric Retail Regulatory Authority ("RERRA") approval:
    - (a) Where LSE is under the jurisdiction of a RERRA, documentation verifying that the RERRA has approved the LSE's PRD Program including the time varying rate structure required to implement the program.
    - (b) Whether or not the LSE is under the jurisdiction of a RERRA, documentation verifying that such rate conforms to PRD implementation standards as specified in the PJM RAA, PJM Operating Agreement, PJM OATT and PJM Manuals.
- If the PRD Provider is not a LSE, documentation conformation to ***Section 3A.4.2.3*** below, verifying that the contractual arrangement with relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements and adheres to PRD implementation standards as specified in PJM RAA, PJM Operating Agreement, PJM OATT and PJM Manuals.
- AMI is required in support of the PRD installation:
    - (a) In jurisdictions where the PRD program is under the jurisdiction of a RERRA, the PRD Provider shall use the AMI infrastructure in conformance with RERRA requirements. Furthermore, the AMI system shall be designed to allow for full implementation of PRD including metering reading requirements, supervisory control requirements, and all other requirements developed under the PJM RAA, PJM Operating Agreements, OATT and PJM Manuals.
    - (b) In jurisdictions where PRD Provider is not required to obtain RERRA approval for the PRD program, the PRD Provider shall use an automated metering infrastructure that effects the needed operational requirements

for PRD. Furthermore, the metering infrastructure shall be designed to allow for full implementation of PRD including meter reading requirements, supervisory control requirements, and all other requirements developed under the PJM RAA, PJM Operating Agreements, OATT and PJM Manuals.

(c) The meter utilized to measure consumption for the purpose of retail billing shall also be the meter utilized to measure consumption for the purpose of PRD participation.

3A.4.2.1 Verification of Retail Rate Structure with LSE

Before PJM will approve a LSE's PRD Plan, PJM will require that the LSE verify that it has received Relevant Electric Retail Regulatory Authority ("RERRA") approval of its time-varying retail rate structure for the referenced load. An LSE that seeks to assert that the RERRA approves or conditionally approves (which condition the LSE asserts has been met) its time varying retail rate structure for the referenced load, shall provide to PJM, within ten (10) business days of PJM's request, either: (a) an order, resolution or ordinance of the RERRA, approving or conditionally approving (which condition the LSE asserts has been met) the LSE's time varying retail rate structure for the referenced load, or (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to existence of a RERRA order, resolution or ordinance approving or conditionally approving (which condition the RERRA legal counsel or the LSE asserts has been met) the LSE's time varying retail rate structure for the referenced load. If the LSE fails to provide the required documentation to PJM within the referenced ten business days, PJM shall reject the LSE's PRD Plan.

In RERRA jurisdictions where a LSE is not required by the RERRA to seek approval from the RERRA for its time varying retail rate structure for the referenced load, the LSE shall provide to PJM, within ten (10) business days of PJM's request, an opinion of either the LSE's legal counsel or the RERRA's legal counsel attesting that the LSE does not need to obtain approval from the RERRA for the LSE's time varying retail rate structure for the referenced load, and that the LSE's time-varying retail rate structure for the referenced load adheres to any guidelines established by the RERRA. If the LSE fails to provide the required documentation to PJM within the ten business days, PJM shall reject the LSE's PRD Plan.

3A.4.2.2 Verification of Contractual Arrangement with PRD Provider

In the case where the PRD Provider is not a LSE, PJM will require the PRD Provider to provide documentation, within (10) business days of PJM's request, that verifies that their contractual arrangement with the relevant end-use customers establishing a time-varying retail rate structure that conforms any RERRA requirements and adheres to PRD implementation standards specified in the PJM RAA, PJM Operating Agreement, PJM OATT or PJM Manuals. The PRD Provider shall provide to PJM, within ten (10) business days of PJM's request, copies of their applicable contracts with end-use customers capable of reducing load in response to price (including any proposed contracts). If the PRD Provider fails to provide any of the required documentation, including but not limited to end-use customer contracts within the ten business days, PJM shall reject the PRD Provider's PRD Plan.

In RERRA jurisdictions where a PRD Provider is not required by the RERRA to seek approval from the RERRA for its contractual arrangement for the referenced load, the PRD Provider shall provide to PJM, within ten (10) business days of PJM's request, an opinion of either the PRD Provider's legal counsel or the RERRA's legal counsel attesting that the PRD Provider does not need to obtain approval from the RERRA for the PRD Provider's contractual arrangement for the referenced load, and that the PRD Provider's contractual arrangement for the referenced load adheres to any guidelines established by the RERRA. If the PRD Provider fails to provide the required documentation within the ten business days, PJM shall reject the PRD Provider's PRD Plan.

3A.4.2.3 PRD Election Requirements

A PRD Provider that is nominating PRD for an RPM Auction must also submit a PRD election (indicating the Sub-zonal/Zonal Nominal PRD Value to be provided at different reservation prices) in the eRPM system by January 15, prior to the Base Residual Auction or Third Incremental Auction for the relevant Delivery Year.

A PRD election must include:

Zonal/Sub-zonal Nominal PRD Value (MW) and Reservation Price ($/MW-day) pair(s) that meet the following requirements.

(a) Up to ten quantity(MW)-price($/MW-day) pair segments for a zone/sub-zone may be submitted

(b) A minimum and maximum Nominal PRD Value quantity must be submitted for each segment

(c) The smallest increment that may be submitted for a Nominal PRD Value MW quantity is 0.1 MW.

(d) The sum of the maximum Nominal PRD Values in the segments must not exceed the sub-zonal/zonal Nominal PRD Value requested for approval by PJM in the PRD Provider's PRD Plan. If PJM approves a lower sub-zonal/zonal Nominal PRD Value than the requested value in their PRD Plan, the PRD Provider will be asked to resubmit their **PRD election such that** the maximum Nominal PRD Values in the segments does not exceed the final sub-zonal/zonal Nominal PRD Value approved by PJM.

(e) A Reservation Price submitted in a segment must be equal to or greater than $0/MW-day. If a PRD Provider does not submit a reservation price for a segment, the reservation price will default to $0/MW-day. A PRD Provider is willing to commit the Nominal PRD level specified in a segment if the RPM Auction Resource Clearing Price applicable to Annual Resources in the zone/sub-zone is equal to or greater than the Reservation Price specified in such segment.

(f) The PRD Provider is willing to accept the commitment of any amount of Nominal PRD Value equal to or greater than the minimum MW amount quantity specified in a segment and equal to or less than the maximum MW amount quantity specified in a segment.

(g) If a PRD Provider's PRD Plan is not approved by PJM, the PRD Provider's Election will be rejected by PJM and not considered in the RPM Auction clearing.

Upon posting of the RPM Auction Results, PJM will notify the PRD Provider via the eRPM system of their sub-zonal/zonal committed Nominal PRD Value. Upon notification by PJM, the PRD Provider has a binding commitment to provide sub-zonal/zonal PRD at the committed level during the relevant Delivery Year.

3A.5 Registration of Price Responsive Demand

A PRD Provider will be required to register price responsive load in eLRS system prior to the start of the Delivery Year and maintain the registration of enough price responsive load in a zone/sub-zone throughout the Delivery Year to satisfy their zonal/sub-zonal PRD commitments.

Only load that meets all the eligibility requirements of PRD can be registered as PRD. The registration of price responsive load must be identified at the substation location within a transmission zone as electrically close as practical to the applicable load (i.e., PNODE).

If during the Delivery Year, the load no longer meets all the eligibility requirements of PRD, the PRD Provider must terminate the initial registration on the date the load no longer meets the eligibility requirements. The PRD Provider may also register new customers throughout the Delivery Year to cover loss of PRD load when customers drop out of the PRD Provider's program.

End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Deliver Year, (i) be registered as Economic Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Sell Offer in any RPM Auction; (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider.

An individual site registration must be submitted for each end-use customer site that is price responsive and has a peak load contribution equal to or greater than 10 KW. The site registration must identify the LSE serving the load at the site, the EDC, PLC, MESL, EDC-assigned loss factor, PNODE, and whether the load is being served by the LSE under the RPM or the FRR Alternative. The MESL in the registration represents the load level that the site is committing to be at during a Maximum Emergency Event.

An aggregate registration may be submitted to aggregate end-use customer sites that have peak load contributions below 10 KW provided such aggregate registration must represent end-use customers served by the same Load Serving Entity under RPM or FRR Alternative and located at the same PNODE.

PJM will receive data to validate the PLC calculation of any EDC who is also an LSE that has registered PRD for a given year.

The Nominal PRD Value calculated for a registration is equal to the [PLC * Final Zonal Peak Load Forecast//Prior Summer Weather Normalized Zonal Coincident Peak] – [MESL in the registration* EDC-assigned loss factor.]

PJM will aggregate the Nominal PRD Values of effective, approved registrations in a zone/sub-zone to determine the PRD Provider's actual Daily Nominal PRD Value in zone/sub-zone for each day during the Delivery Year.

The deadline for the submittal of a PRD registration in the eLRS system is one day before the tenth business day prior to the start date that a PRD registration is effective so that adequate time is provided for the EDC and LSE to confirm the registration data. During the Delivery Year, if the load identified in the approved PRD registration will no longer meet the PRD eligibility requirements, a request to terminate the PRD registration on the last day that such load meets the PRD eligibility requirements must be submitted in eLRS within two business days prior to the date that the PRD registration is to terminate. A PRD registration must be in an approved status by the start date of the registration and be effective on the delivery day in order for such registration to be counted towards meeting the PRD Provider's committed sub-zonal/zonal Nominal PRD Value for the relevant delivery day.

For a PRD Provider, the MW amount of PRD that is currently registered by the PRD Provider at the time of PRD Plan submittal may be considered as Existing PRD and not be subject to a Price Responsive Demand Credit Requirement.

3A.6 Performance Requirements of Price Responsive Demand

Once a PRD Provider commits PRD for the Delivery Year, the PRD Provider will be subject to both daily commitment compliance during the Delivery Year and event compliance during Maximum Emergency Events during the Delivery Year. In the absence of a Maximum Emergency Event during the relevant Delivery Year that required a PRD registration to respond, such registration would be required to test during the Delivery Year.

A PRD Provider cannot use replacement capacity to reduce a MW shortfall for PRD commitment compliance, failure to perform during a Maximum Emergency Event, or failure to perform during a test. However, a PRD provider may register additional price responsive demand throughout the Delivery Year to cure a daily commitment compliance shortfall or avoid additional event compliance shortfalls. In addition, a PRD Provider may transfer the obligation to provide PRD to another PRD provider through a bilateral transaction.

3A.6.1 PRD Commitment Compliance

A PRD Provider must register enough PRD prior to the start of the Delivery Year and maintain enough Price Responsive Demand registrations throughout the Delivery Year to satisfy their sub-zonal/zonal PRD commitment for RPM or FRR.

PRD commitment compliance will be evaluated on a daily basis throughout the Delivery Year. PJM will determine the actual Daily Nominal PRD Value of the PRD Provider in a Sub-Zone/Zone for RPM or FRR based on the registration information provided in the eLRS system. If a PRD Provider's actual Daily Nominal PRD Value in a Sub-Zone/Zone for RPM is less than their committed Nominal PRD Value in Sub-Zone/Zone for RPM, the PRD Provider will be subject to a Daily PRD Commitment Compliance Penalty in the Sub-zone/Zone for the MW shortfall. If a PRD Provider's actual Daily Nominal PRD Value in a Sub-Zone/Zone for FRR is less than their committed Nominal PRD Value in Sub-Zone/Zone for FRR, the PRD Provider will be subject to a Daily PRD Commitment Compliance Penalty in the Sub-zone/Zone for the MW shortfall.

3A.6.2 Maximum Emergency Event Compliance

Sub-zonal/zonal committed PRD is required to reduce to a level based on the sub-zonal/zonal MESL in the registration system upon PJM declaration of a Maximum Emergency Event during that Delivery Year. During the Delivery Year, PRD Providers for which committed Price Responsive Demand does not respond consistent with the sub-zonal/zonal commitment during emergency conditions will be subject to a PRD Maximum Emergency Event Compliance Penalty.

The performance of Price Responsive Demand will be measured and verified whenever PJM declares a Maximum Emergency Event in sub-zone/zone. PRD Providers are responsible for the submittal to PJM of all meter information required to complete this measurement and verification for each PJM Maximum Emergency Event during the Delivery Year. PJM requires that actual metered data at the end-use customer site for all hours during the PJM Maximum Emergency Event be submitted to PJM via the eLRS system within 60 days of the event, with accountability if for failure to do so. PJM's review of the PRD Provider's performance and the calculation of a net MW shortfall in a sub-zone/zone for a Maximum Emergency Event are to be completed by the PJM and any resulting PRD Maximum Emergency Event Compliance Penalties billed by the later of (i) third billing month following the Maximum Emergency Event or (ii) the month of December of the Delivery Year.

Compliance is measured for a PRD registration upon declaration of a PJM Maximum Emergency Event in same sub-zone/zone of such PRD registration and when the PRD Curve associated with such registration in the PJM Energy Market has a price point at or below the highest Real-Time LMP recorded during the Maximum Emergency Event.

The MW shortfall for a PRD registration = highest hourly integrated metered load for end-use customer(s) associated with the registration – adjusted MESL of the registration.

If the PRD Provider failed to submit actual metered data for the end-use customer site for all hours during the PJM Maximum Emergency Event, the MW shortfall for such registration for the Maximum Emergency Event will be equal to the Expected Peak Load Value of the registration minus the adjusted MESL of the registration.

The MW shortfall for a PRD registration will be capped at the PRD commitment level (MW) for such registration on the day of the event. The PRD Provider's committed Zonal (or Sub-Zonal LDA) Nominal PRD Value on the day of the event is allocated to the PRD Provider's registrations in the zone (or sub-zonal LDA) pro-rata based on the Nominal PRD Value of the registrations to determine the PRD commitment level for such registrations.

For event compliance, the MESL of the registration is adjusted to account for the fact that actual load can be greater than the PJM 50/50 load forecast during an emergency event. The MESL in the registration will be multiplied by the higher of 1.0 or (the ratio of the actual non-PRD zonal load at the time of RTO unrestricted peak for the Delivery Year to the non-PRD final zonal peak load forecast for the Delivery Year.)

The adjusted MESL for a registration shall equal the MESL reported in the registration * service level adjustment factor.

The service level adjustment factor = higher of 1.0 or (actual zonal load – actual total PRD load in zone/ (Final Zonal Peak Load Forecast-final total Zonal Expected Peak Load Value of PRD in Zone), where:

Actual zonal load is equal to the actual unrestricted zonal peak load at the time of the RTO peak.

Actual total PRD load in zone is the hourly integrated metered load for all end-use customers' registered to meet a PRD commitment for RPM or FRR Alternative at the time of the RTO unrestricted peak for the Delivery Year plus any add-backs for PRD in accordance with Manual 19: Load Forecast and Analysis. The final total Zonal Expected Peak Load Value of PRD in the zone is equal to the sum of the Zonal Expected Peak Load Values as determined from approved PRD registrations that are effective on the day of the RTO unrestricted peak for the Delivery Year

A single service level adjustment factor applies for each zone and is used in the measuring compliance for all Maximum Emergency Events during the Delivery Year. The service level adjustment factor must be greater than or equal to 1.0.

The event compliance evaluation for a registration is completed for every, full clock hour for which the Maximum Emergency Event was in effect. In addition, for any partial clock hours during which the Event was in effect, at the PRD Provider's option, PJM will verify either that the load was reduced to the adjusted MESL level within 15 minutes of the emergency procedures notification regardless of the response rate submitted in the associated PRD Curve in the PJM Energy Market, or that the hourly integrated value of the load was at or below the adjusted MESL. If not verified, the MW shortfall for the partial clock hour will be equal to the hourly integrated load for the whole hour minus the adjusted MESL.

The highest of MW shortfalls calculated for each hour in the Maximum Emergency Event will be the MW shortfall for the registration for the Maximum Emergency Event. A positive MW shortfall for the registration represents under-compliance for the Maximum Emergency Event. A negative MW shortfall for the registration represents over-compliance for the Maximum Emergency Event.

The MW shortfalls of the PRD Provider's PRD registrations in a sub-zone/zone that were expected to respond are aggregated to determine a PRD Provider's sub-zonal/zonal net shortfall during a Maximum Emergency Event.

If the PRD Provider registered PRD to satisfy RPM PRD commitments and PRD to satisfy FRR PRD commitments, the PRD Provider's sub-zonal/zonal net shortfall for a Maximum Emergency Event will be allocated into a net shortfall for RPM and a net shortfall for FRR based on the percentage of the total under-compliance MWs in the sub-zone/zone due to under-compliance MWs of registrations tied to RPM versus FRR.

The PRD Provider's sub-zonal/zonal net shortfall for RPM for a Maximum Emergency Event may be reduced by the amount of daily MW shortfall for RPM commitment compliance if the PRD Provider is assessed a Daily PRD Commitment Compliance Penalty on the day of the Maximum Emergency Event.

The PRD Provider's sub-zonal/zonal net shortfall for FRR for a Maximum Emergency Event may be reduced by the amount of daily MW shortfall for FRR commitment compliance if the PRD Provider is assessed a Daily PRD Commitment Compliance Penalty on the day of the Maximum Emergency Event.

3A.6.3 PRD Test Compliance

If PJM does not declare during the relevant Delivery Year a Maximum Generation Emergency in zone that requires the registered PRD to reduce to the Maximum Emergency Service Level then such registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency may be called during June through October or the following May of the relevant Delivery Year. If a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum

Emergency Service Level is called during the relevant Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registrations.

All PRD registrations in a zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies PJM 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election.

Multiple tests may be conducted; however only one test result may be submitted for each end-use customer site in eLRS for test compliance evaluation. Test data must be submitted in eLRS on or after June 1 and no later than July 14th after the Delivery Year.

Testing compliance is measured for a PRD registration in a manner similar to event compliance.

The MW testing shortfall for a PRD registration = hourly integrated metered load for end-use customer(s) associated with the registration during test – adjusted MESL of the registration.

The MW shortfall for a PRD registration will be capped at the PRD commitment level (MW) for such registration on the day of the test. The PRD Provider's committed Zonal (or Sub-Zonal LDA) Nominal PRD Value on the day of the test is allocated to the PRD Provider's registrations in the zone (or sub-zonal LDA) pro-rata based on the Nominal PRD Value of the registrations to determine the PRD commitment level for such registrations.

The adjusted MESL for a registration shall equal the MESL reported in the registration * service level adjustment factor. The same zonal service level adjustment factors that would be calculated for event compliance are used for test compliance.

Positive MW shortfalls represent underperformance for a PRD registration. Negative MW shortfalls represent over performance for a PRD registration.

The test compliance results of the PRD Provider's PRD registrations in a zone that were expected to test are aggregated to determine a PRD Provider's net zonal testing shortfall.

If the PRD Provider registered PRD to satisfy RPM PRD commitments and PRD to satisfy FRR PRD commitments, the PRD Provider's net zonal testing shortfall will be allocated into a net zonal testing shortfall for RPM and a net zonal testing shortfall for FRR based on the percentage of the total under-compliance MWs in the zone due to under-compliance MWs of registrations tied to RPM versus FRR.

The PRD Provider's net testing shortfall in a zone for RPM shall be reduced by the PRD Provider's summer daily average of the MW shortfalls for RPM PRD commitment compliance. Any remaining positive net testing shortfall in the zone for RPM will be assessed a PRD Test Failure Charge.

The PRD Provider's net testing shortfall in a zone for FRR shall be reduced by the PRD Provider's summer daily average of the MW shortfalls for FRR PRD commitment compliance. Any remaining positive net testing shortfall in the zone for FRR will be assessed a PRD Test Failure Charge.

3A.7 PRD Bilaterals

A PRD Provider may transfer the obligation to provide PRD bilaterally to another PRD Provider during the Delivery Year.

The following are the business rules that apply to PRD bilateral transactions:

- PRD bilateral transactions must be reported in the eRPM system.
- Both parties of the PRD transaction must confirm the transfer of a PRD commitment from the seller (transferor) to the buyer (transferee) via the eRPM system prior to the start date of the transaction.
- PRD bilateral transactions must be in the "Approved" status by the start date of the transaction or the status of such transaction will be changed to "PJM Withdrawn".
- The smallest increment of committed Nominal PRD Value that may be transferred is 0.1 MW.
- PRD transactions must specify:
  - start and end data for the transaction
  - the amount of Nominal PRD Value (in MW) to be transferred
  - the sub-zone/zone in which the Nominal PRD Value to be transferred was committed
  - whether the Nominal PRD Value to be transferred was committed to RPM or the FRR Alternative
  - the RPM Auction (BRA or Third IA) for which the Nominal PRD Value to be transferred was committed (if committed to RPM)
- The eRPM system will validate that the Seller has the committed Nominal PRD Value in the sub-zone/zone to transfer for the term of the transaction.
- To the extent that the Nominal PRD Value to be transferred has a Price Responsive Demand Credit Requirement, the Buyer must have sufficient credit in place prior to PJM approving the PRD transaction.
- As a result of an approved PRD transaction, the buyer that is assuming the seller's PRD commitment and obligations will be subject to PRD performance requirements to the extent of such transfer and for the term of the transaction.
- The seller shall be relieved of its PRD commitment and any Price Responsive Demand Credit Requirements for the Nominal PRD Value transferred for the term of the transaction.

Section 4: Supply Resources in the Reliability Pricing Model

Welcome to the *Supply Resources in RPM* section of the *PJM Manual for the PJM Capacity Market*. In this section, you will find the following information:

- An overview description of supply in the Reliability Pricing Model (see "Overview of Supply in the Reliability Pricing Model")
- The business rules for generation resources (see "Generation Resources")
- The business rules for load management products (see "Load Management Products")
- The business rules for energy efficiency resources (see "Energy Efficiency Resources")
- The business rules for qualified transmission upgrades (see "Qualified Transmission Upgrades")
- The business rules for bilateral transactions (see "Bilateral Transactions")
- The business rules for resource portfolios in RPM (see "Resource Portfolios")
- The credit requirements in RPM (see "Credit Requirements")

4.1 Overview of Supply in the Reliability Pricing Model

In the Reliability Pricing Model, the supply of installed capacity is procured to meet demand as a function of the clearing of the RPM Auctions. In each auction, a supply curve is defined based on the offers submitted by providers with installed capacity resources. Supply, valued as unforced capacity, that is procured in the RPM multi-auction clearing process, ensures that sufficient resources are committed to meet the PJM Reliability Principles and Standards.

A party's supply resource portfolio in eRPM may consist of:

- Generation Resources;
- Load Management Resources;
- Energy Efficiency Resources; and
- Qualifying Transmission Upgrades.

Key qualifications and requirements for generation resources are presented in Existing Generation, Planned Generation, and Bilateral Unit-Specific Transaction sections of this Manual. Key qualifications and requirements for load management products are presented in the Load Management section of this Manual. Key qualifications and requirements for Energy Efficiency Resources are presented in the Energy Efficiency Resources section of this Manual. Key qualifications and requirements for Qualified Transmission Upgrades are presented in the Qualified Transmission Upgrade section of this Manual.

Prior to any RPM auction, RPM suppliers must confirm the modeling of each of their capacity resources. RPM suppliers must verify the following characteristics of generation units and demand resources:

- Zone assignment
- LDA assignment
- Unit Location by State
- Unit Type

4.2 Generation Resources

A party's Generation Resource portfolio may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Qualifications and requirements for generation resources are presented in the sections below.

4.2.1 Existing Generation Resources - Internal

Existing generation located within the PJM region is eligible to be offered into RPM Auctions or traded bilaterally if it meets the following requirements:

- The unit is pre-certified by PJM as meeting the generation deliverability test. PJM's certification process for internal generating resources is described in ***the Tariff and the Operating Agreement***
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit.
- The unit resides in the eRPM resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having an "Approved" Capacity Modification in the eRPM system.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.
- The unit must have been offered in the Base Residual Auction for the Delivery Year in order to be eligible to offer into the First, Second or Third Incremental Auctions for that Delivery Year.

4.2.2 Existing Generation Resources - External

Existing generation located outside the PJM region is eligible to be offered into an RPM Auction if it meets the following requirements:

- An indication of the intended ATC path to deliver the existing external capacity into PJM is provided. (Firm transmission service from the unit to the border of PJM and generation deliverability in PJM must be demonstrated by the start of the Delivery Year.)

- The unit resides in the eRPM resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having a "Provisionally Approved" or "Approved" unit-specific transaction with "External Party" (i.e., "EXT") as the "Seller" of the transaction in the eRPM system.
- Twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's EFORd.
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit.
- The external capacity without firm transmission must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.

The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year. Existing generation located outside the PJM region is eligible to be traded bilaterally if the unit resides in the eRPM resource portfolio of a signatory of the PJM Operating Agreement through the accomplishment of an "Approved" unit-specific transaction with "External party" (i.e., "EXT") as the "Seller" of the transaction in the eRPM system. An "Approved" unit-specific transaction status will not be granted until firm transmission service from the unit to the border of PJM has been obtained and generation deliverability has been demonstrated into PJM by (1) obtaining firm point-to-point transmission service on the PJM OASIS from the border into the PJM transmission system (this applies to service on the PJM transmission system) or (2) obtaining "Network External Designated" transmission service with an expected completion date prior to June 1st of the delivery year. Either of the above options for demonstrating deliverability may require transmission upgrades to be completed prior to June 1st of the delivery year. All of the above options follow the study process for participant-funded upgrades as defined in Part VI of the PJM Open Access Transmission Tariff. The following requirements for existing external generation are still applicable:

- Twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's EFORd.
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.

- A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.

Existing generation located outside the PJM region that is offered into an RPM auction is treated in the auction process as capacity delivered into the unconstrained area of the RTO.

If existing generation located outside the PJM region cleared in the Base Residual Auction, First Incremental, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction and does not procure firm transmission service from the unit to the PJM border and demonstrate generation deliverability by the start date of associated bilateral transaction, the status of the associated bilateral transaction in the eRPM system will be changed from "Provisionally Approved" to "PJM Withdrawn".

4.2.3 Planned Generation Resources - Internal

Planned generation that is participating in PJM's Regional Transmission Expansion Planning Process (RTEPP) is eligible to be offered into PJM's RPM Auctions if it meets the following requirements:

- The planned unit's start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, an Impact Study Agreement has been executed for the unit to participate in the Base Residual Auction.[4]
- An Interconnection Service Agreement (ISA) or Wholesale Market Participant Agreement (WMPA) has been executed for the unit to participate in an Incremental Auction.
- A planned unit with an Interim ISA can offer only into the BRA or Incremental Auction for which the Interim ISA is valid.
- A Capacity Modification for the planned unit has been submitted and "Provisionally Approved" in eRPM.
- Planned Generation Resources must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- If the planned generation was committed through the Base Residual Auction and the ISA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied" so that the planned generation will no longer be included in a resource provider's eRPM Generation Resource portfolio.
- If an ISA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification will need to be

[4] During the Transition Phase, the minimum requirement is an executed Interconnection Service Agreement for the 2007/2008 and 2008/2009 Base Residual Auctions and an Executed Impact Study Agreement for the 2009/2010 – 2010/11 Base Residual Auctions.

submitted and "Provisionally Approved" in order to be re-included in a resource provider's eRPM Generation Resource portfolio.

- If the planned generation is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied". A new Capacity Modification will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.

4.2.4 Planned Generation Resources – External

Planned external generation is eligible to be offered into PJM's RPM Auctions. Such resources will be treated in a manner comparable to planned internal generation resources and existing external generation resources. Prior to participation in any RPM Auction, the Resource Provider must demonstrate that it has executed an interconnection agreement (functionally equivalent to a System Impact Study Agreement for a Base Residual Auction and an Interconnection Service Agreement for an Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being connected, and if applicable with the transmission provider. A planned external generation resource must provide evidence to PJM it has been studied as a Network Resource, or such other similar interconnection product in the external Control Area.

- An indication of the intended ATC path to deliver the external planned capacity into PJM is provided. (Firm transmission service from the unit to the border of PJM and generation deliverability in PJM must be demonstrated by the start of the Delivery Year.)
- The planned unit's start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, a functionally equivalent System Impact Study Agreement has been executed for the unit to participate in the Base Residual Auction.
- A functionally equivalent Interconnection Service Agreement has been executed for the unit to participate in an Incremental Auction.
- A Capacity Modification for the planned unit has been submitted and "Provisionally Approved" in eRPM.
- Planned Generation Resources must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- If the planned generation was committed through the Base Residual Auction and the ISA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied" so that the planned generation will no longer be included in a resource provider's eRPM Generation Resource portfolio.
- If an ISA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification will need to be

submitted and "Provisionally Approved" in order to be re-included in a resource provider's eRPM Generation Resource portfolio.

- If the planned generation is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied". A new Capacity Modification will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.
- Once operational, the resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- Once operational, the resource owner or operator performs winter and summer testing as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.

4.2.5 Equivalent Demand Forced Outage Rate (EFORd)

Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. ***See Generator Resource Performance Indices Manual (M-22) for equation.***

The EFORd of a unit is based on forced outage data from an October through September period. If a unit does not have a full one-year history of forced outage data, the EFORd will be calculated using class average EFORd and the available history as described in the ***Reliability Assurance Agreement, Schedule 5, Section B***.

Since no forced outage data is collected for intermittent resources, an EFORd is not calculated for intermittent resources. The EFORd of intermittent resources is set to zero in the eRPM system.

New units are initially assigned a class average EFORd. The class average EFORds that are used by PJM to calculate a unit's EFORd are posted to the PJM website by November 30 prior to the Delivery Year.

The Effective EFORd is the EFORd that is effective for the delivery day in the eRPM system. Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the eRPM system. During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year.

The EFORd that is effective for the Delivery Year is considered locked in the eRPM system by November 30 prior to the execution of the Third Incremental Auction.

4.2.6 Capacity Modifications (CAP Mods)

Capacity Modifications (CAP MODs) are a type of eRPM transaction used by generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in eRPM, or to request a MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

The purpose of a CAP MOD is to establish the installed capacity value of a generation resource in the eRPM system. CAP MOD transactions represent permanent changes to the installed capacity value of a generation unit.

CAP MODs are also used by a generation owner to establish the capacity value of an intermittent resource to be offered into the PJM Capacity Market and by PJM to establish the Delivery Year capacity value of an intermittent resource.

The following are business rules that apply to Capacity Modifications (CAP Mods):

- CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and "Provisionally Approved" or "Approved" by PJM in the eRPM system prior to the opening of the Base Residual Auction's or Incremental Auction's bidding window in order for the CAP MODs to be considered in a party's Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction, Incremental Auction or bilateral unit-specific transaction.
- All other CAP MODs must be submitted a minimum of 2 business days prior to the start date of the CAP MOD. The CAP MOD must be "Approved" by PJM in the eRPM system prior to the start date of the CAP MOD in order to be considered in a party's final Daily Generation Resource Position.
- If the status of a "Provisionally Approved" CAP MOD changes to "Denied" or "PJM Withdrawn", there will be no change to any party's RPM Resource Commitments.
- CAP MODs cannot be created during an RPM Auction's bidding window and clearing week.
- CAP MODs that are not in the "Approved" status by the start date of the CAP MOD will have their status changed to "PJM Withdrawn".
- CAP MODs that would cause the summer rating of a generation resource or the capacity value of an intermittent resource to exceed such unit's Capacity Injection Rights will be "Denied" by PJM.
- CAP MODs for wind resources that would cause the capacity value for a wind resource to be less than 0.85 times the Design Capacity Value of the wind resource will be "Denied" by PJM, unless the generation owner provides data to PJM and the IMM that supports a capacity value that is less than 0.85 times the Design Capacity Value. The Design Capacity Value of a wind resource is equal to a Capacity Factor times the Net Maximum Capacity as described in ***Rules and Procedures for Determination of Generating Capability (M-21).***

4.3 Load Management Products

Load management is the ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

A load management program (e.g., Direct Load Control, Firm Service Level, or Guaranteed Load Drop program) is eligible to be offered by a resource provider as:

(1) A **Demand Resource (DR)** offered into the Base Residual Auction or an Incremental Auction and paid the Resource Clearing Price.

4.3.1 Requirements of Load Management Products in RPM

In order to offer a Demand Resource in an RPM Auction, a demand resource provider must submit no later than 15 business days prior to the RPM Auction a Demand Resource Sell Offer Plan (DR Sell Offer Plan) in accordance with Attachment C of this Manual. Actual deadline date for a DR Sell Offer Plan for an RPM Auction is provided in the RPM Auction Schedule posted on the pjm website. A demand resource provider with a PJM approved DR Sell Offer Plan for the RPM Auction will be permitted to offer their Demand Resource(s) into such RPM Auction, provided the additional demand resource requirements in section 4.3.3 are met.

Demand resources that clear in an RPM Auction will have an RPM Resource Commitment for the relevant Delivery Year. Demand resources that are committed to an FRR Capacity Plan will have an FRR Capacity Plan Commitments for the relevant Delivery Year. A resource provider who has RPM Resource Commitments or FRR Capacity Plan Commitments for their demand resource must meet the following requirements:

- Must be registered in the Emergency Load Response Program (see more detail in later the Emergency Load Response Registration section) prior to the start of the relevant Delivery Year.
- Have the capability to retrieve electronic messages from PJM which notify curtailment service providers of a load management event in accordance with PJM Manual 1: Control Center and Data Exchange Requirements.
- Provide (or contract with another party to provide) supplemental status reports during the Delivery Year, detailing availability of the load management resource, as requested by PJM System Operations in accordance with the *PJM Manuals*;
- Provide (or contract with another party to provide) customer-specific compliance and verification information within 45 days after the end of the month in which a PJM-initiated Load Management event occurred, in accordance with the Load Management Compliance section of Section 8 of this Manual.
- Provide load drop estimates for all Load Management events (whether initiated by PJM or the resource provider) in accordance with *PJM Manual 19: Load Forecasting & Analysis.*

These requirements are described in terms of the customer response and qualifications. The specifics of the customer contract and tariffs are the responsibility of the resource provider and the regulatory process. PJM does not have direct involvement with customers. The entity requesting load management must verify that each customer's load management meets the following criteria:

- Availability for PJM-initiated interruptions in accordance with the availability requirements of the demand resource product type.
- Limited DR – Limited DR is available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time.
- Extended Summer DR (Effective 2014/2015 Delivery Year) – Extended Summer DR is available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time.
- Annual DR (Effective 2014/2015 Delivery Year) – Annual DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
- Load management must be able to be implemented within two hours of notification to the resource provider of a PJM-initiated load management event.
- Initiation of load interruptions upon request of PJM must be within the authority of the resource provider dispatcher without any additional approvals being required.
- DLC programs are certified based on load research and customer subscription data. Load Research guidelines are outlined in ***PJM Manual 19: Load Forecasting & Analysis.***

4.3.2 Types of Load Management Programs

PJM recognizes three types of Load Management programs:

- Direct Load Control (DLC) – Load management that is initiated directly by the resource provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).
- Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the resource provider's market operations center or its agent.
- Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the resource provider's market operations center or its agent. Typically, the load

reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of recognized Load Management Program, there can be two notification periods:

- Step 1 (Short Lead Time) – Load management which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.
- Step 2 (Long Lead Time) – Load management which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

4.3.3 Demand Resources

Both Existing and Planned Demand Resources may participate in RPM Auctions, provided the resource resides in a party's portfolio for the duration of the Delivery Year. A Demand Resource is added to a party's portfolio through the creation of a Demand Resource Modification transaction in eRPM. More information on Demand Resource Modification transactions is available in the next section.

Existing Demand Resources are those MWs on a demand resource identified in a pre-registration process in the eRPM system prior to the RPM Auction. The Nominated DR Values (in MWs) associated with end-use customer sites that the Curtailment Service Provider (CSP) has under contract for the current Delivery Year (i.e., end-use customer sites registered in PJM eLRS system for the current Delivery Year)[5] and that the CSP intends to have under contract for the auction Delivery Year are considered Existing MWs.

Planned Demand Resources are defined as resources that do not currently have the capability to provide reduction in demand or to otherwise control load in PJM, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year. Planned Demand Resources are those MWs on a demand resource that the CSP intends to offer in the RPM Auction in excess of the CSP's Existing MWs on such demand resource.

Planned Demand Resources must establish an RPM Credit Limit prior to an RPM Auction. Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

A resource provider may offer Demand Resources (Planned or Existing) associated with Behind the Meter Generation for an entire Delivery Year into the Base Residual or Incremental Auctions. If the DR offer clears in an RPM auction for a given Delivery Year, the Behind the Meter Generation cannot be netted from load for the purposes of calculating the Peak Load Contributions for that Delivery Year. Requests for Behind the Meter changes for capacity obligations must be received by PJM by December 1 prior to the start of the Delivery Year as outlined in ***PJM Manual 14D: Load Generator Operational Requirements.***

[5] For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM eLRS system for the subsequent Delivery Year may also be considered as existing DR provided the registrations are in "Confirmed" status by specified deadlines established by PJM and communicated to CSPs in advance of the DR Sell Offer Plan submittal deadline.

If offering as a Demand Resource in the Base Residual Auction or Incremental Auction, a sell offer must be submitted in the Base Residual Auction or Incremental Auction. Demand Resources offered and cleared in a Base Residual or Incremental Auction will receive the corresponding LDA Resource Clearing Price determined by the optimization algorithm. However, prior to 2013/2014, if a resource provider cannot provide Demand Resource data on individual LDA basis in a Zone with multiple LDAs, Demand Resources will be paid a Weighted Zonal Resource Clearing Price based on the resource provider's distribution of registered sites in each LDA that are approved before June 1st of the Delivery Year. Effective 2013/2014, resource providers must offer DR resources in the lowest level LDA in order to receive proper payment. No Weighted Prices will be calculated effective 2013/2014.

4.3.4 Demand Resource Modifications (DR Mods)

In order to offer a Demand Resource into an RPM Auction, the resource must be in a party's portfolio for the duration of the Delivery Year. A Demand Resource Modification transaction is the mechanism to add a demand resource to a party's portfolio. Demand Resource Modifications (DR MODs) are a type of eRPM transaction used by PJM to track an increase or decrease of the nominated value of the DR resource in a party's resource portfolio in eRPM. The following are business rules that apply to Demand Resource Modifications (DR Mods):

- DR MODs must be submitted by the resource provider within the eRPM system for Planned Demand Resources and for Demand Resources that have not yet participated in an RPM Auction.
- DR MODs may be submitted to reflect changes in the Peak Load Contributions or EDC loss factors of customers associated with a Demand Resource.
- PJM will "provisionally approve" DR MODs for Planned DR resources after verifying that the Planned DR resource has posted the appropriate credit and after completing a review of the submitted timeline and milestones to ensure that the Planned Demand Resource will be available for the start of the Delivery Year.
- PJM will "provisionally approve" DR MODs for existing demand response sites that have not yet participated in an RPM Auction after completing a review of the sites currently registered by this resource provider in the PJM Load Response system to ensure that the nominated value of the Demand Resource will be available for the start of the Delivery Year.
- PJM will "approve" DR MODs for DR resources once the demand resource sites have been registered and approved for the Full Program Option of the Emergency Load Response Program in the PJM Load Response system.
- DR MODs must be in a "Provisionally Approved" or "Approved" status in order for the DR MOD to be considered in a party's Demand Resource Position and in the calculation of Available ICAP to offer for an RPM Auction.
- DR MODs that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

4.3.5 Emergency Load Response Registration

Emergency Load Response Registration is the process of providing the following information through the submittal of an Emergency Load Response registration into PJM's Load Response system (eLRS). As part of an Emergency Load Response registration, resource providers will submit the following types of information:

- Customer-specific load management information for planning and verification purposes (i.e., EDC account number, Zone, etc)
- Customer-specific information to establish nominated load management levels (i.e., Peak Load Contribution, EDC Loss Factor, notification period, Firm Service Level data, Direct Load Control data, Guaranteed Load Drop data)
- Load Management Program information (Demand Resource Name if applicable)
- Load Management product type for customer site (Limited DR, Extended DR, Annual Summer DR) (Effective with the 2014/2015 Delivery Year)
- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process

A resource provider who has RPM or FRR Resource Commitments for their demand resource must register customers in a capacity-related Emergency Load Response Programs. Demand Resources have the option of registering in either the Full Emergency or Capacity Only Emergency Programs.

The Full Emergency Program and Capacity Only Emergency Program enable a resource provider that has approved registration for the Delivery Year prior to the applicable registration deadline to receive Capacity Credits, in the form of RPM Auction Credits, for that Delivery Year. Full Emergency Program resource providers may claim an energy settlement for a PJM-initiated Load Management Events. Capacity Only Emergency Program resource providers may not claim an energy settlement for a PJM-initiated Load Management Event for Capacity Only Emergency registrations.

Customer sites registered in the Energy Only Emergency Program are not eligible to receive capacity credits.

Effective with the 2014/2015 Delivery Year, a provider with RPM or FRR Resource Commitments for their Demand Resource must register customer sites that are of the same product-type (Limited, Extended Summer, or Annual) as the committed Demand Resource.

A completed Emergency Load Response registration in eLRS for a DR resource must be submitted no later than one day before the tenth business day preceding the relevant Delivery Year. All registrations that have not been approved on or before May 31st preceding the relevant Delivery year shall be rejected by PJM.

Full details of the Emergency Load Response registration and approval process may be found in ***Section 10 of PJM Manual for Scheduling Operations (M-11).***

4.3.6 End-Use Customer Aggregation

A resource provider may aggregate multiple end-use customer sites to create a single Demand Resource for the purposes of submitting an offer in the RPM Auctions, if all the end-use customer sites have the same following characteristics:

- Curtailment Service Provider
- Electric Distribution Company (EDC)
- Transmission Zone (or sub-zonal LDA)

The mechanism for aggregating end-use customer sites to create a single Demand Resource is to select the same Demand Resource for multiple end-use customer sites during the process of registering end-use customers as Full Emergency Load Response customers.

4.3.7 Determination of Nominated Values for Load Management

Once an end-use customer is registered in the Emergency Load Response Program (Full Emergency or Capacity Only), a nominated load reduction value is calculated for that customer. The determination of the value of the load reduction is consistent with the process for determination of the capacity obligation for the customer. Nominated value of a load management resource is equivalent to the Installed Capacity value of generation resource. Nominated load reductions are effective for an entire RPM Delivery Year.

For existing Demand Resources, the maximum load reduction (used in determining the Nominated DR Value) is based on the Peak Load Contributions in place at the time of the Full Program Option of the Emergency Load Response Program registration in the Load Response system.

<u>Nominated Value of Firm Service Level Resources</u>

The nominated value for a Firm Service Level customer will be based on the Peak Load Contribution for the customer, as determined by the 5CP methodology.

The nominated value for a Firm Service Level (FSL) customer will be equal to the difference between its Peak Load Contribution (PLC) and its pre-determined firm load adjusted for system losses

*Nominated Value of FSL = PLC – (FL * LossF)*

Where:

PLC = the customer's EDC-assigned Peak Load Contribution;

FL = Firm Load level;

LossF = the customer's EDC-assigned loss factor.

<u>Nominated Value of Guaranteed Load Drop Resources</u>

The nominated value for a Guaranteed Load Drop (GLD) customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the resource provider. The value nominated shall not exceed the customer's Peak Load Contribution.

Nominated Value of GLD = GLD (LossF)

Where:

GLD =Customer's Load Reduction;

LossF = the customer's EDC-assigned loss factor.

Nominated Value of Direct Load Control Resources

The nominated value for a Direct Load Control (DLC) program will be based on load research and customer subscription. The value of the program is equal to the PJM-approved per-participant load reduction (evaluated at average peak day weather conditions and adjusted for the switch operability rate) multiplied by the number of active participants, adjusted for system losses.

*Nominated Value of DLC = PPI * Cust * LossF*

Where:

PPI = the PJM-approved Per-Participant Impact;

Cust = the number of active participants;

LossF = the EDC-assigned loss factor.

The per-participant impact is to be estimated at long-term average local weather conditions at time of the RTO summer peak. Load research studies to support per-participant impacts must comply with the Guidelines for DLC load research studies presented in ***PJM Manual 19: Load Forecasting & Analysis of this Manual.***

4.3.8 Determination of the UCAP Value of Load Management

The Unforced Capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the Demand Resource Factor (DR Factor) and the Forecast Pool Requirement (FPR).

$$UCAPvalueofLoadManagementProduct = NominatedValue \times DRFactor \times FPR$$

4.4 Energy Efficiency Resources

An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then-current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of Schedule 6 (section M) of the Reliability Assurance Agreement. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site (during the defined EE Performance Hours[6]) that is not reflected in the peak load forecast used for the Base Residual Auction for the Delivery Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention.

An EE installation is eligible to offer into an RPM auction if it meets the following criteria:

- EE installation must be scheduled for completion prior to DY;

[6] The EE Performance Hours are between the hour ending 15:00 Eastern Prevailing Time (EPT) and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday.

- EE installation is not reflected in peak load forecast posted for the BRA for the DY initially offered;
- EE installation exceeds relevant standards at time of installation as known at time of commitment;
- EE installation achieves load reduction during defined EE Performance Hours; and
- EE installation is not dispatchable[7].

An Existing EE Resource is defined as an EE Resource with a PJM approved Post-Installation Measurement & Verification (M&V) Report. A Planned EE Resource is defined as an EE Resource that does not have a PJM approved Post-Installation M&V Report. An EE Resource that clears in an RPM Auction will receive the Resource Clearing Price of the Locational Deliverability Area in which the EE Resource resides.

An EE Resource may participate in RPM Auctions for a maximum of up to four consecutive Delivery Years. The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year. The time period of Energy Efficiency installations and their associated eligibility, in addition to the modeling of EE Resources in the PJM Capacity Market, is presented in ***PJM Manual 18B: Energy Efficiency Measurement &Verification,***

An EE Resource must meet the following minimum requirements:

- Submit Initial Measurement &Verification (M&V) Plan no later than 30 days prior to RPM Auction in which the EE Resource is initially offered;
- Submit Updated M&V Plan no later than 30 days prior to next RPM auction in which EE Resource is subsequently offered;
- Establish credit with PJM Credit Department prior to RPM Auction (for Planned EE Resources);
- Submit Energy Efficiency Resource Modification (EE MOD) in eRPM system;
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed;
- Submit Updated Post-Installation M&V Reports no later than business 15 days prior to each subsequent Delivery Year that the EE Resource is committed; and
- Permit Post- Installation M&V Audit(s) by PJM or Independent Third Party.

PJM Manual 18B: Energy Efficiency Measurement & Verification establishes the requirements for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports, and the M&V Audit.

4.4.1 Determination of Nominated Value of EE Resource

The Nominated EE Value of an EE Resource is the expected average demand (MW) reduction during the defined EE Performance Hours in the Delivery Year. The minimum Nominated EE Value accepted in the PJM Capacity Market is 0.1 MW. The Measurement & Verification (M&V) Plan describes the methods and procedures for determining the

[7] Dispatchable demand may be offered as a Demand Resource in the PJM Capacity Market.

Nominated EE Value of an EE Resource and confirming that the Nominated EE Value is achieved.

The Nominated EE Value approved by PJM in EE Resource Provider's Initial/Updated M&V Plan establishes the Nominated EE Value that may be offered in an RPM Auction.

The last Post-Installation M&V Report submitted and approved by PJM prior to the Delivery Year that the EE Resource is committed establishes the final Nominated EE Value that is used to measure RPM Commitment Compliance during the Delivery Year. Failure to submit an Initial/Updated Post-Installation M&V Report or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Final Nominated EE Value equal to zero MWs for the relevant Delivery Year. If an M&V Audit is performed and results finalized prior to the start of a Delivery Year, the Nominated EE Value confirmed by the Audit becomes the Final Nominated EE Value that is used to measure RPM Commitment Compliance during the Delivery Year. If the M&V Audit is performed and results finalized after the start of a Delivery Year, the Nominated EE Value confirmed by the M&V Audit becomes the basis to determine if any incremental RPM Commitment Compliance Shortfall needs to be assessed retroactively from June 1 of the Delivery Year to May 31 of the Delivery Year.

4.4.2 Determination of the UCAP Value of EE Resource

The Unforced Capacity (UCAP) value of an Energy Efficiency Resource is equal to the Nominated EE Value of the EE Resource multiplied by the Demand Resource Factor (DR Factor) and the Forecast Pool Requirement.

$$UCAPvalueofEE\,\mathrm{Re}source = NominatedEEValue \times DRFactor \times FPR$$

4.4.3 Energy Efficiency Resource Modifications (EE MODs)

In order to offer an Energy Efficiency Resource into an RPM Auction, the resource must be in a party's portfolio for the duration of the Delivery Year. An Energy Efficiency Resource Modification transaction is the mechanism to add an EE Resource to a party's portfolio.

Energy Efficiency Resource Modifications (EE MODs) are a type of eRPM transaction used by PJM to track an increase or decrease of the Nominated EE Value of an EE Resource in a party's resource portfolio in eRPM. The following are business rules that apply to EE MODs:

- EE MODs must be submitted by the resource provider within the eRPM system for an EE Resource that has not yet participated in an RPM Auction.
- EE MODs may be submitted to reflect changes in the number of planned installations, changes in the demand reduction value based on M&V activities, and changes in EDC loss factors.
- PJM will "provisionally approve" an EE MOD after PJM has approved the Initial/Updated M&V Plan and the Nominated EE Value, and adequate credit for the EE Resource has been posted.
- PJM will "approve" an EE MOD once PJM has reviewed the Initial/Updated Post-Installation M&V Report and approved the Final Nominated EE Value of the EE Resource.

- PJM will "deny" an EE MOD if the increase in Nominated EE Value results in the total value of the EE Resource being greater than the PJM approved Final Nominated EE Value for the Delivery Year.
- EE MODs must be in a "Provisionally Approved" or "Approved" status in order for the EE MOD to be considered in a party's EE Resource Position and in the calculation of Available ICAP to offer for an RPM Auction.
- EE MODs that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

4.5 Qualified Transmission Upgrades

A Qualifying Transmission Upgrade may be offered into the Base Residual Auction to increase import capability into a transmission-constrained LDA (Sink LDA) from a Source LDA. Such transmission upgrade must meet the following minimum requirements.

- Must have been approved and an incremental import capability value must have been assigned by the PJM Planning Dept at least 45 days prior to the auction.
- The planned transmission upgrade in-service date must be on or before the start of the Delivery Year.
- At a minimum, a Facilities Study Agreement must be executed for the proposed transmission upgrade, in order for approval to be granted and the transmission upgrade
- Must conform to all applicable standards of the PJM Regional Transmission Expansion Planning Process.
- Qualified Transmission Upgrades must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

If a Qualifying Transmission Upgrade that was cleared in the Base Residual Auction is not completed by the start of the Delivery Year, the party who submitted the offer shall provide a replacement in the form of an equivalent amount of capacity resource within the Sink LDA by the start of the delivery Year. If replacement capacity is not provided, a Transmission Upgrade Delay Penalty shall apply.

A Qualifying Transmission Upgrade that cleared in the Base Residual Auction will be paid the Locational Price Adder of the Sink LDA less the Locational Price Adder of the Source LDA, multiplied by the megawatt quantity of incremental import capability cleared. A cleared Qualifying Transmission Upgrade is not automatically included in CETL analysis for future delivery years.

Once the Qualifying Transmission Upgrade is in service, the Qualifying Transmission Upgrade is eligible to continue to offer the approved incremental import capability value into future RPM Auctions.

4.6 Bilateral Transactions

Bilateral Transactions in the Reliability Pricing Model are transactions for capacity between a buyer and seller. Bilateral Transactions may be reported to PJM for inclusion in the PJM billing process for unit-specific capacity or for non unit-specific capacity. Parties in all bilateral transactions reported to PJM agree to indemnify PJM against non-performance by their counterparties in such transactions.

PJM posts reference prices at various points in order to facilitate bilateral trading on the part of market participants. The posted pricing points include LDA and Hub pricing points (associated with a Base Residual Auction (BRA) Resource Clearing Price in a LDA), Net Load pricing points (associated with a Final Zonal Capacity Price less Final Zonal CTR Credit Rate), PZonal pricing points (associated with Preliminary Zonal Capacity Price), FZonal (associated with Final Zonal Capacity Price), FCTR pricing points (associated with Final Zonal CTR Credit Rate), and FILR pricing points (associated with the Final Zonal ILR Price), and 3IA pricing points (associated with a Third Incremental Auction (3IA) Resource Clearing Price in an LDA). The available pricing points and their definitions are posted on the PJM website.

Additional pricing points will be added by PJM if requested by stakeholders. However, the definition of the pricing points will remain static once created.

4.6.1 Unit-Specific Bilateral Transactions

The purpose of reporting a unit-specific bilateral transaction to PJM (regardless of the type of capacity transacted) is to transfer the rights to or control of a specified amount of installed capacity from the Seller to the Buyer. Bilateral contracts for unit-specific capacity resources may be offered into PJM's RPM if these products meet the requirements specified in this Manual.

PJM will provide electronic bulletin board functionality in eRPM. The bulletin board allows participants to post and view requests to buy or offers to sell capacity resources. The purpose of the bulletin board functionality is to facilitate bilateral transaction activity.

4.6.2 Entering Unit-Specific Bilateral Transactions

Unit-specific bilateral transactions reported to PJM may wholly or partially offset an LSE's Locational Reliability Charges in the PJM billing process provided that Available installed capacity purchased through the bilateral transaction is directly offered and cleared in a Base Residual Auction or Incremental Auction or is designated as a self-scheduled resource in a Base Residual Auction (i.e., the RPM Auction Credits received may offset the Locational Reliability Charges assessed in your PJM bill).

The smallest increment of installed capacity that may be reported to PJM as unit-specific transactions is 0.1 MW.

PJM does not recognize "slice of system" or unforced capacity credit bilateral transactions in RPM Auctions.

Both parties of a unit-specific transaction must confirm the transfer of installed capacity from the seller to the buyer via the eRPM system prior to the start date of the transaction.

Unit-specific transactions to an "External Party" (i.e., "EXT") must be in "Pending PJM" status two business days prior to the start date of the transaction.

All unit-specific bilateral transactions that cover the Delivery Year must be in "Provisionally Approved" or "Approved" status in the eRPM system prior to the opening of the Base Residual Auction or an Incremental Auction's bidding window in order for the transactions to be considered in a party's Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction or an Incremental Auction or to be used for self-scheduling in the Base Residual Auction.

Unit-specific transactions cannot be created during an RPM Auction's bidding window and clearing week.

Unit-specific transactions that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

Unit–specific bilateral transactions may be reported for the following installed capacity types: Available, Unoffered, or Cleared.

Unit specific transactions reported for either Available or Unoffered capacity must specify:

- The unit to be transacted
- A start and end date for the transaction
- An installed capacity (ICAP) MW value

Unit specific transactions reported for Cleared capacity must specify:

- The unit to be transacted
- A start and end date for the transaction
- The auction in which the unit cleared
- An unforced capacity (UCAP) MW value. Once approved, the unforced capacity MW value will be converted to an installed capacity MW value using the then-current Effective EFORd for the specified unit. The installed capacity MW value is capped at the ICAP Owned by the Seller.

The following are business rules that apply to Unit-Specific Bilateral Transactions:

- If available capacity type is selected, the eRPM system will validate that the Seller has Daily Available ICAP to offer for the entire term of the transaction. The Daily Available ICAP to offer on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP - (Daily RPM Resource Commitments/(1-Effective EFORd)) – Daily FRR Capacity Plan Commitments.
- Available installed capacity purchased through a bilateral unit-specific transaction that is registered in PJM's eRPM system may be directly offered into the Base Residual Auction or Incremental Auctions or designated as a self-scheduled resource in the Base Residual Auction.
- If unoffered capacity type is selected, the eRPM system will validate that the Seller has Daily Unoffered ICAP to offer for the entire term of the transaction and validate that the Seller is either External Party (EXT) or FRR Entity.

- The unoffered capacity type may be selected for a unit-specific bilateral transaction if selling a unit externally (formerly known as "delisting") after the Base Residual Auction has been cleared for the specified transaction dates. To delist a unit before the Base Residual Auction has been run, a party may select the Available capacity type to transact installed capacity to an External Party (EXT).
- If cleared capacity is selected, the eRPM system will validate that the Seller has cleared capacity to offer for the entire term of the transaction.
- Approved unit-specific transactions reported to PJM for Cleared capacity will result in a transfer of the Auction Credit for the specified number of UCAP MW from the Seller to the Buyer. In addition, the RPM Resource Commitment for the specified number of UCAP MWs is also transferred from the Seller to the Buyer.
- The Buyer in a unit-specific transaction for cleared capacity will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of such transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the unit-specific capacity transaction for cleared capacity.
- To the extent that capacity identified in the unit-specific transaction for cleared capacity is a resource that has an RPM Credit Requirement, the Buyer must have sufficient credit in place with respect to the credit exposure associated with the obligations of the acquired RPM Resource Commitment.

4.6.3 Exporting a Generation Resource

Exporting (formerly known as "Delisting") a generation resource is accomplished by reporting a bilateral transaction with "External Party" (i.e., "EXT") listed as the "Buyer" in the unit-specific transaction.

Exporting any portion of a generation resource below a party's Daily RPM Resource Commitments/(1-Effective EFORd) plus Daily FRR Capacity Plan Commitments for the term of the transaction is not permitted. Only Available or Unoffered ICAP on the unit may be exported.

Exporting of a generation resource may only be done by the party that submitted the Capacity Modification for the unit.

If a portion of a generation resource is to be exported, appropriate documentation must be submitted to PJM to demonstrate that the party exporting the generation resource has a financially and physically firm commitment to an external sale of its capacity and therefore, is exempt from the offer requirement for capacity resources in ***Attachment DD, Section 6.6 of the PJM Open Access Tariff.***

In order for a generation resource that is being exported to be reflected in a party's Available ICAP Position for an RPM Auction, the associated unit-specific transaction must be in an "Approved" status by the opening of the RPM Auction's bidding window.

Capacity Export Charge

A Capacity Export Transmission Customer may procure capacity in one PJM Zone and export the capacity from another Zone to outside PJM. Under the FERC approved tariff effective June 1, 2008, the Capacity Export Transmission Customer will pay a Capacity

Export Charge and receive a credit similar to the CTR credit if the Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported is higher than the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located. The Capacity Export Charge collected less the credit will be allocated to the LSEs in the Zone from which capacity is exported.

This Capacity Export Charge and credit are assessed daily and billed monthly. These calculations are independent from the CTR calculations based on Base Residual Auction and all Incremental Auctions. The LSE CTR credits and the Incremental CTR credits will not be changed due to Capacity Export Charge/credit calculations.

A Capacity Export Charge is applicable when Long-Term Firm Transmission Service is reserved from export source to export interface.

If more than one Zone forms the interface with the Control Area to which capacity is exported, the Export Reserved Capacity will be apportioned among the Zones. The Export Reserved Capacity is completely apportioned to the Zone if a fully controllable facility crosses the interface (e.g. dc line). The power flow distribution among multiple interface zones for a capacity export would be based on the PJM RTEP Base Power Flow case for the applicable Delivery Year. The power flow distribution calculations are done by modeling the de-listed generator as the source and the designated external load as the sink for the specific capacity exports to be analyzed.

Capacity Export Transmission Customer incurs for each day a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service multiplied by (the Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported minus the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located).

To recognize the value of firm Transmission Service held, the Capacity Export Transmission Customer receives a credit similar to Capacity Transfer Rights (CTRs) credits. The credit is the Final Zonal Capacity price difference used in determining the Capacity Export Charge times Export Customer's Allocated Share of the Export Path Import.

4.6.4 Importing an External Generation Resource

Importing an external generation resource is accomplished by entering into a bilateral transaction with "External Party" (i.e., "EXT") listed as the "Seller" in the unit-specific transaction. Unit-specific transactions that represent capacity imports will not be granted a "Provisionally Approved" status unless an indication of the intended ATC path to deliver the external capacity to PJM is provided. An "Approved" unit-specific transaction status will not be granted until firm transmission service from the unit to the border of PJM has been obtained and generation deliverability has been demonstrated into PJM.

External generators must demonstrate generation deliverability into PJM by (1) obtaining firm point-to-point transmission service on the PJM OASIS from the border into the PJM transmission system (this applies to service on the PJM transmission system) or (2) obtaining "Network External Designated" transmission service with an expected completion date prior to June 1st of the delivery year. Either of the above options for demonstrating deliverability may require transmission upgrades to be completed prior to June 1st of the delivery year. All of the above options follow the study process for participant-funded upgrades as defined in **Part VI of the PJM Open Access Transmission Tariff**.

Unit-specific transactions that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

Unit-specific transactions that are not "Approved" should refer to the RPM credit business rules for their associated credit requirements.

4.6.5 Treatment of Unit-Specific Capacity Transactions that Start/End Mid-Delivery Year

Unit-specific transactions reported with a Start Date that does not correspond to June 1 or an End Date that does not correspond to May 31 will result in installed capacity that cannot be offered into the Base Residual Auction since a single party does not own the installed capacity for the entire Delivery Year. In addition, this installed capacity will be tracked as Unoffered Capacity after the Base Residual Auction. To address this issue, PJM will facilitate a voluntary process to enable the installed capacity to be offered into the Base Residual Auction for the Delivery Year.

In order to participate, each party of the unit-specific transaction that starts/end Mid-Delivery Year must sign and submit a Self-Schedule Authorization Form found in ***Attachment B of this Manual***, which authorizes PJM to self-schedule the capacity on behalf of the parties in the Base Residual Auction for the Delivery Year. The Authorization Form must be submitted to RPM_Hotline@pjm.com at least 5 business days prior to the opening of the bidding window.

Each party of the unit-specific transaction that starts/ends Mid-Delivery Year must submit a new unit-specific transaction in eRPM with "Self-Scheduling Coordinator (SELFSC)" as the Buyer prior to the opening of the Base Residual Auction bidding window, so the capacity will be transferred into the SELFSC account for the entire Delivery Year at the time of the Base Residual Auction.

Provided the Self-Schedule Authorization Forms are received and the required unit-specific transactions are submitted, PJM will self-schedule and clear the capacity on-behalf of the parties in the Base Residual Auction for the Delivery Year. A submitted EFORd equal to the Effective EFORd at the time of the Base Residual Auction will be used in the resource-specific sell offer in the Base Residual Auction.

After the Base Residual Auction results are posted, PJM will submit unit-specific transactions for Cleared MWs with "SELFSC" as the Seller to transfer capacity back to the Parties (i.e., Buyer in the unit-specific transaction) for the appropriate time periods. No confirmation is required by the Buyer of the unit-specific transaction. The approved unit-specific transactions for Cleared MWs will result in the transfer of ICAP Owned, RPM Resource Commitments, and Auction Credits from the SELFSC account to the Buyer. The Buyer of the Cleared MWs is responsible for any Capacity Resource Deficiency Charges that may be assessed during the term of the unit-specific transaction. In addition, the Buyer of the Cleared MWs is responsible for their share of any Peak-Hour Period Availability Charges, Generation Resource Rating Test Failure Charges, or Peak Season Maintenance Compliance Penalty Charges that may be assessed during the Delivery Year.

4.6.6 Auction Specific MW Transactions

RPM Market Participants have the ability to report Auction Specific MW Transactions to PJM through the eRPM system. Auction Specific MW Transactions must be for the transfer of physical MW of capacity from a seller to a buyer at the location of the physical resources identified as supplying the transaction.

The following are business rules that apply to Auction-Specific MW Transactions

- Auction Specific MW Transactions are not eligible to be offered in an RPM auction.
- Auction Specific MW Transactions for a Delivery Year may be submitted following the completion of the Third Incremental Auction for the delivery year to which the transaction applies.
- Both the Buyer and the Seller of Auction Specific MW Transaction must confirm the Auction Specific MW Transaction via the eRPM system before the start date of the Delivery Year.
- An Auction Specific MW Transaction must specify the buyer, seller, start and end dates of the transaction.
- The Seller of the Auction Specific MW must also specify the resource(s) (generation resource or demand resource or Energy Efficiency Resource), Auction Type (Base, First, Second, Third, or Conditional), and the MW amount of Auction Specific MW to be transacted from each resource. PJM will verify that the MW of capacity from each of the resources identified as supplying the Auction Specific MW Transaction have cleared in an RPM auction and that at least the MW of cleared capacity indicated for each resource is not committed in any other bilateral transactions. If such sufficient cleared capacity does not exist on any of the indicated resources, PJM will reject reporting of the transaction.
- Auction Specific MW Transactions may not extend past the last day of the delivery year containing the start date of the transaction.
- Auction Specific MW Transactions are priced at the weighted average of the Resource Clearing Prices from the RPM auctions in which the MW from the units supplying the transaction cleared.
- The smallest increment that may be transacted through an Auction Specific MW Transaction is 0.1 MW.
- The Seller of the Auction Specific MW is subject to all applicable resource performance assessments.
- The Buyer will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of the Auction Specific MW transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the Auction Specific MW transaction.
- PJM reserves the right under the PJM Operating Agreement and PJM Open Access Transmission Tariff, to deny reporting of Auction Specific MW Transactions in the event one of the parties fails to meet any requirements for such reporting.
- The Seller of an Auction Specific MW Transaction will receive a charge equal to the transaction amount (in MW) times the price associated with in the transaction.
- The Buyer of an Auction Specific MW Transaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction.

4.6.7 Cleared Buy Bid Transactions

RPM Market Participants have the ability to report Cleared Buy Bid Transactions through the eRPM system. A Cleared Buy Bid Transaction allows the holder of a Cleared Buy Bid from an Incremental Auction to transfer Cleared Buy Bid MWs to another party for the term of the transaction. A Cleared Buy Bid Transaction will not change the resource position or load obligation of an entity. However, the Buyer may use the Cleared Buy Bid MWs as a replacement resource in a Replacement Capacity Transaction.

The following are business rules that apply to Cleared Buy Bid Transactions

- Cleared Buy Bid MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of Cleared Buy Bid MWs must confirm the Cleared Buy Bid transaction via the eRPM system by 23:59 EPT before the start date of the transaction.
- A Cleared Buy Bid Transaction must specify the buyer, seller, start and end dates of the transaction, the transaction amount (in MW), the LDA and Incremental Auction associated with the Cleared Buy Bid.
- The smallest increment that may be transacted through a Cleared Buy Bid Transaction is 0.1 MW.
- Cleared Buy Bid transaction results in the "Buyer" receiving the Cleared MWs in the applicable LDA and the associated Incremental Auction Charges that would have been assessed to the Seller for the term of the transaction.

4.6.8 Locational Unforced Capacity (UCAP) Transactions

RPM Market Participants have the ability to report Locational UCAP Transactions through the eRPM system. A Locational UCAP Transaction allows a party with available resource-specific capacity to transfer Locational UCAP (MWs) to another party. A Locational UCAP Transaction will not change the resource position or load obligation of an entity. However, the Buyer may use the Locational UCAP as a replacement resource in a Replacement Capacity Transaction.

The following are business rules that apply to Locational UCAP Transactions:

- Locational UCAP MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of Locational UCAP MWs must confirm the Locational UCAP Transaction via the eRPM system by 23:59 EPT before the start date of the transaction.
- Locational UCAP transactions for a Delivery Year will be restricted as follows during the following periods:
- Prior to the locking of the Delivery Year EFORd (Nov. 30th prior to the Delivery Year): Locational UCAP transactions will not be accepted.
- After the locking of the Delivery Year EFORd, but before the Delivery Year's Third Incremental Auction bidding window opens: Locational UCAP transactions may be accepted; however, the Buyer of the Locational UCAP transaction must demonstrate prior to the Third Incremental Auction that the Locational UCAP was used in a replacement capacity transaction. If the Buyer fails to enter into a replacement

capacity transaction prior to the Third Incremental Auction, the Locational UCAP transaction will be denied by PJM.

- During the Delivery Year's Third Incremental Auction: Locational UCAP transactions will not be accepted.
- After the Delivery Year's Third Incremental: Locational UCAP transactions will be accepted.
- A Locational UCAP Transaction must specify the buyer, seller, product type (i.e., Limited, Extended Summer, or Annual) effective with the 2014/2015 Delivery Year, start and end dates of the transaction.
- The Seller of the Locational UCAP must also specify the resource (generation resource or demand resource) and the MW amount of locational UCAP to be transacted. The resource specified in the transaction must be of the same product type specified in the Locational UCAP transaction.
- The smallest increment that may be transacted through a Locational UCAP Transaction is 0.1 MW.
- A Locational UCAP transaction results in an RPM Resource Commitment (in UCAP terms), equal to the MW amount of locational UCAP transacted, being placed on the Seller's resource for the term of the transaction.
- The Seller of the Locational UCAP retains ownership of the resource specified in the Locational UCAP Transaction.
- The Seller of the Locational UCAP is subject to all applicable resource performance assessments.
- The Buyer in a Locational UCAP transaction will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of such transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the Locational UCAP transaction.

4.7 Resource Portfolio

A party's resource portfolio in eRPM may consist of Generation Resources, Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades. A party's Generation Resource portfolio may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Qualification requirements for generation resources are presented in Existing Generation, Planned Generation, and Bilateral Unit-Specific Transaction Sections of this Manual.

4.7.1 Resource Position for Generation Resources

A party's Daily Generation Resource Position is calculated dynamically by the eRPM system for each unit and is equal to the party's Daily ICAP Owned on a unit multiplied by one minus the unit's Effective EFORd.

A party's Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases. The Installed Capacity (ICAP) Value of a unit is based on the summer net dependable rating of the unit as determined in accordance with ***PJM Manual for the Rules and Procedures for the Determination of Generating Capability (M-21).***

A unit that is in a party's Generation Resource portfolio may be traded bilaterally if the party has Daily Available ICAP to offer from the unit for the entire term of the bilateral unit-specific transaction. If the Daily Available ICAP for the unit varies for the term of the bilateral unit-specific transaction, only the minimum Daily Available ICAP may be sold in the bilateral unit-specific transaction.

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP - (Daily RPM Resource Commitments/(1-Effective EFORd)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP = DailyICAPOwned - DailyUnofferedICAP - \left(\frac{DailyRPMResourceCommitments}{1 - EffectiveEFORd}\right) - DailyFRRCapacityPlanCommitments$$

A unit that is in a party's Generation Resource portfolio may be offered into RPM Auctions if the party has available capacity to offer from the unit for the entire term of the RPM Auction Year. For each RPM Auction, PJM will calculate a Current Available ICAP Position, Minimum Available ICAP Position, and Maximum Available ICAP Position.

A party's Current Available ICAP Position on a unit for an RPM Auction is equal to the minimum Daily Available ICAP for such unit during the Delivery Year.

$$CurrentAvailableICAPPosition_{unit} = Min(DailyAvailableICAP)$$

A party's Minimum Available ICAP Position represents the minimum amount that must be offered into an RPM Auction. A party's Minimum Available ICAP Position on a unit for an RPM Auction is equal to the *minimum* Daily Minimum Available ICAP for such unit during the Delivery Year.

$$MinimumAvailableICAPPosition_{unit} = Min(DailyMinAvailableICAP)$$

A party's Daily Minimum Available ICAP is equal to Daily ICAP Owned minus the Daily Unoffered ICAP minus Daily Cleared ICAP in RPM Auctions minus Daily FRR Capacity Plan Commitments. Daily Cleared UCAP in RPM Auctions is converted to Daily Cleared ICAP using the greater of the EFORd $_{1\,yr}$ at the time of the Base Residual Auction, EFORd $_{5\,yr}$ at the time of the Base Residual Auction, or the party's Sell Offer EFORd from the Base Residual Auction.

$$\text{Daily Min Available ICAP} = DailyICAPOwned - DailyUnofferedICAP - \left[\frac{DailyClearedUCAP}{(1 - Max(\text{BRA EFORd 1yr}, BRAEFORd\,5yr, \text{BRA SellOfferEFORd}))}\right] - DailyFRRCapPlanCommitments$$

A party's Maximum Available ICAP Position represents the maximum amount that a participant may offer into an RPM Auction. A party's Maximum Available ICAP Position on a unit for an RPM Auction is equal to the *minimum* Daily Maximum Available ICAP for such unit during the Delivery Year.

$$MaximumAvailableICAPPosition = Min(DailyMaxAvailableICAP)$$

A party's Daily Maximum Available ICAP is equal to Daily ICAP Owned minus the Daily Unoffered ICAP minus Daily Cleared ICAP in RPM Auctions minus Daily FRR Capacity Plan Commitments. Daily Cleared UCAP in RPM Auctions is converted to Daily Cleared ICAP using a zero EFORd.

$$\text{Daily MaxAvailableICAP} = DailyICAPOwned - DailyUnofferedICAP - \left[\frac{DailyClearedUCAP}{(1-0))}\right] - DailyFRRCapacityPlanCommitments$$

For the Base Residual Auction and Third Incremental Auction, a party's Minimum Available ICAP Position and Maximum Available ICAP Position for a unit will be equal to the party's Current Available ICAP Position for such unit.

A party's Daily Unoffered ICAP for a specific unit is calculated by adding the sum of any Daily Unoffered ICAP for such unit in RPM Auctions to Daily Unoffered ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

$$DailyUnOfferedICAP_{\text{unit}} = DailyUnofferedICAP_{\text{RPMAuctions}} + DailyUnofferedICAP_{\text{BilateralSales/Purchases}}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a generation resource is equal to the party's Minimum Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$DailyUnofferedICAP_{\text{GenResource}} = MinimumAvailableICAP\,Positionunit - OfferedICAP$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity and the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific unit are equal to the total amount of installed capacity that was committed from the unit for the FRR Capacity Plan.

A party's Daily RPM Generation Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(1-Effective EFORd).

$$DailyRPM\,Position_{\text{GenResources}} = (Daily\ ICAPOwned - Daily\ FRRCapPlan\ Commitments - Daily\ Unoffered\ ICAP) \times (1 - EffectiveEFORd)$$

During the Delivery Year, a party's Daily RPM Generation Resource Position is compared to their Daily RPM Resource Commitments for the generating unit to determine if a Capacity Resource Deficiency Charge is to be assessed.

4.7.2 Resource Position for Demand Resources

A party's Demand Resource portfolio may consist of existing Demand Resources or Planned Demand Resources. Qualification requirements for Demand Resources are presented in Load Management Products Section of this Manual.

A party's Daily Nominated DR Value for a specific demand resource is equal to the Daily Nominated DR Value as determined by party's "Provisionally Approved" or "Approved" DR Modifications.

A party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the eRPM system and is equal to the Daily Nominated DR Value * DR Factor * Forecast Pool Requirement.

$$DailyResourcePosition_{Demand\,Resource} = DailyNominatedDRValue \times DRFactor \times FPR$$

A Demand Resource that is in a party's Demand Resource portfolio may be offered into RPM Auctions, if there is Daily Available ICAP to offer from the Demand Resource for the entire term of the RPM Auction.

For a party, the Daily Available ICAP for a specific demand resource is equal the resource's Daily Nominated DR Value – Daily Unoffered ICAP - ((Daily RPM Resource Commitments/(DR Factor *Forecast Pool Requirement)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP_{DR} = DailyNominatedDRValue - (\frac{DailyRPMResourceCommitments}{(DRFactor \times FPR)}) - DailyFRRCapCommitments$$

A party's Daily Unoffered ICAP for a specific demand resource is calculated by adding the sum of any Daily Unoffered ICAP for such demand resource in RPM Auctions.

$$DailyUnOfferedICAP_{demandresource} = \sum DailyUnofferedICAP_{RPMAuctions}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a specific demand resource is equal to the demand resource's Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$Daily\ Unoffered\ ICAP_{DemandResource} = Available\ ICAP\ Position - Offered\ ICAP$$

A party's Available ICAP Position for a specific demand resource is equal to the minimum Daily Available ICAP for such demand resource during the Delivery Year.

$$AvailableICAPPosition_{Demand\,Resource} = Min(DailyAvailableICAP)$$

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such demand resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific demand resource are equal to the total amount of Nominated DR that was committed from the demand resource for the FRR Capacity Plan.

A party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily Nominated DR Value – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)* DR Factor * Forecast Pool Requirement.

$$DailyRPMPosition_{DR} = (DailyNomDRValue - DailyFRRCapPlanCom) \times DRFactor \times FPR$$

During the Delivery Year, a party's Daily RPM Demand Resource Position is compared to their Daily RPM Resource Commitments for the demand resource to determine if a Capacity Resource Deficiency Charge is to be assessed on the delivery day.

4.7.3 Resource Position for Energy Efficiency Resources

A party's EE Resource portfolio may consist of existing or planned EE Resources. Qualification requirements for EE Resources are presented in Energy Efficiency Resource Section of this Manual.

A party's Daily Nominated EE Value for a specific EE Resource is equal to the Daily Nominated EE Value as determined by party's "Provisionally Approved" or "Approved" EE Modifications.

A party's Daily EE Resource Position for an EE Resource is calculated dynamically by the eRPM system and is equal to the Daily Nominated EE Value * DR Factor * Forecast Pool Requirement.

$$DailyResourcePosition_{EE\ Resource} = DailyNominatedEEValue \times DRFactor \times FPR$$

An EE Resource that is in a party's EE Resource portfolio may be offered into RPM Auctions, if there is Daily Available ICAP to offer from the EE Resource for the entire term of the RPM Auction.

For a party, the Daily Available ICAP for a specific EE Resource is equal the resource's Daily Nominated EE Value – Daily Unoffered ICAP - ((Daily RPM Resource Commitments/(DR Factor *Forecast Pool Requirement)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP_{EE} = DailyNominatedEEValue - DailyUnofferedICAP - \left(\frac{DailyRPMResourceCommitments}{(DRFactor \times FPR)}\right) - DailyFRRCapCommitments$$

A party's Daily Unoffered ICAP for a specific EE Resource is calculated by adding the sum of any Daily Unoffered ICAP for such EE Resource in RPM Auctions.

$$DailyUnOfferedICAPEE\ Resource = \sum DailyUnofferedICAP_{RPMAuctions}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a specific EE Resource is equal to the EE Resource's Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$Daily\ Unoffered\ ICAP_{EEResource} = Available\ ICAP\ Position - Offered\ ICAP$$

A party's Available ICAP Position for a specific EE Resource is equal to the minimum Daily Available ICAP for such EE Resource during the Delivery Year.

$$AvailableICAPPosition_{EE\ Resource} = Min(DailyAvailableICAP)$$

A party's Daily RPM Resource Commitments for a specific EE Resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such EE Resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific EE Resource are equal to the total Nominated EE Value that was committed from the EE Resource for the FRR Capacity Plan.

A party's Daily RPM EE Resource Position for a specific EE Resource is equal to the (Daily Nominated EE Value – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)* DR Factor * Forecast Pool Requirement.

$$DailyRPMPosition_{EE} = (DailyNomEEValue - DailyFRRCapPlanCom - DailyUnofferedICAP) \times DRFactor \times FPR$$

During the Delivery Year, a party's Daily RPM EE Resource Position is compared to their Daily RPM Resource Commitments for the EE Resource to determine if a Capacity Resource Deficiency Charge is to be assessed on the delivery day.

4.7.4 Resource Position for Qualified Transmission Upgrades

A party's Qualifying Transmission Upgrade portfolio may consist of planned Qualifying Transmission Upgrades. Qualification requirements for Qualifying Transmission Upgrades are presented in Qualifying Transmission Upgrade Section of the RPM Business Rules.

A Qualifying Transmission Upgrade that is in a party's Qualifying Transmission Upgrade portfolio may be offered into a Base Residual Auction if incremental import capability value into Sink LDA from a Source LDA has been approved by PJM System Planning Department.

A party's Daily Qualifying Transmission Upgrade Position for a Qualifying Transmission Upgrade is calculated dynamically by the eRPM system and is equal to the incremental import capability value into Sink LDA from a Source LDA that has been assigned by PJM System Planning Department.

A party's Daily RPM Resource Commitments for a specific Qualifying Transmission Upgrade are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such Qualifying Transmission Upgrade in RPM Auctions to any decreases of RPM Resource Commitments due to the specification of replacement resources.

During the Delivery Year, a party's Daily RPM Qualifying Transmission Upgrade Position for a qualifying transmission upgrade is compared to their Daily RPM Resource Commitments for the qualifying transmission upgrade to determine if a Transmission Upgrade Delay Penalty is to be assessed.

4.8 Credit Requirements

The purpose of the RPM credit requirement is to encourage future physical performance, but not necessarily fully guarantee financial obligations related to Capacity. Credit requirements for participating in the RPM, therefore, may be different from the other requirements established separately in the PJM Credit Policy, which are intended for other activities and general financial obligations to PJM.

These business rules are intended to be descriptive of the credit requirements for participants in the RPM, but if any conflict arises between provisions in these rules and provisions in the PJM Operating Agreement or PJM Open Access Transmission Tariff (which includes the PJM Credit Policy as Attachment Q), then the provisions in the Operating Agreement and/or Tariff shall govern.

Since LSE payments due to PJM are included in monthly PJM bills, LSE payment obligations are considered to already be measured and covered by provisions of PJM's Credit Policy. Accordingly, no separate credit requirement will be imposed on LSEs under the RPM.

Participants offering into an RPM Auction existing resources (whether generators, demand resources, energy efficiency resources, or external generation resources with firm transmission), are not required to establish credit for the RPM Auctions.

Participants offering into an RPM Auction any Planned Demand Resource, Planned Energy Efficiency Resource, Planned Generation Resource, Qualified Transmission Upgrade, or external capacity without firm transmission (these four together considered herein to be Resources Requiring Credit for RPM) must establish an RPM Credit Limit prior to an RPM Auction

Participants nominating PRD in advance of a BRA or Third Incremental Auction (for use in RPM Auction or FRR) must establish an RPM Credit Limit before submitting the PRD Plan in advance of the BRA or Third Incremental Auction.

4.8.1 RPM Credit Limit

Acceptable sources of credit for the RPM Credit Limit may be either of the following:

- Any unsecured credit or collateral available, according to provisions of the PJM Credit Policy, which has not already been designated or required for financial obligations under the Credit Policy or for other financial obligations within PJM.
- For RPM credit purposes only, if a supplier has a history of being a net seller into PJM, on average, over the past 12 months, then PJM will count as available unsecured credit twice the average of that participant's total net PJM bills over the past 12 months.
- A supplier may combine more than one source of credit for RPM credit purposes. Credit provided for RPM must be non-cancelable until at least 10 days after payment is due for the last month for which a committed financial obligation could be created or owed.

For Resources Requiring Credit for RPM, credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction. For price responsive demand requiring credit, credit requests should be made to PJM's Treasury Department at least two weeks prior to the deadline for submitting the PRD Plan. Credit previously established with PJM for general market activity will not be available for RPM unless the participant specifically makes such a request to the PJM Treasury Department.

Although credit provided by a participant may be administratively separated for RPM (or FTR, etc.), all credit supplied by a PJM member or customer, whether or not designated for RPM (or FTR, or any other PJM obligation), may be utilized to cover any PJM financial obligation, should the member or customer default.

PJM will return or release RPM credit provided by participants upon request, as long as such release would not cause a participant's RPM Credit Requirement and/or Price Responsive Demand Credit Requirement to exceed its RPM Credit Limit. Furthermore, PJM reserves the right to establish a maximum frequency of such returns or releases, but no less frequent than once per calendar quarter.

A participant must, at all times, maintain its RPM Credit Limit at least sufficient to meet its RPM Credit Requirement and/or Price Responsive Demand Credit Requirement. If a participant's RPM Credit Requirement and/or Price Responsive Demand Credit Requirement ever exceeds its RPM Credit Limit, PJM may exercise any of the remedies afforded by the Credit Policy, Tariff, Operating Agreement, or other agreements, business rules or manuals, including demand for additional credit and/or declaration of default. Failure to exercise a remedy at any given time shall not preclude PJM from exercising such remedy at a later time.

4.8.2 RPM Credit Requirement

An RPM Credit Requirement will be established for all participants that are offering into an RPM Auction or have already committed into RPM any Resources Requiring Credit for RPM. The RPM Credit Requirement will be equal to the sum of the individual credit requirements for such resources. The credit requirement for a given resource offered into an RPM auction will be a fixed Auction Credit Rate times the unforced MW offered, times an RPM Credit Adjustment Factor. The credit requirement for a given resource committed into RPM will be a fixed Auction Credit Rate times the unforced MW committed, times an RPM Credit Adjustment Factor.

<u>RPM Credit Adjustment Factor</u>

- The RPM Credit Adjustment Factor for a given resource depends on its status in becoming a fully qualified resource as follows The Credit Adjustment Factor for all Resources Requiring Credit for RPM will be one ("1") except as follows:
- For Planned Demand Resources, the Credit Adjustment Factor will be (1-X), where "X" is the Nominated DR that is certified through an Emergency Load Response Registration divided by the Nominated DR value in the DR Modification for the planned demand resource.
- For Planned Energy Efficiency Resource, the Credit Adjustment Factor will be (1-X), where "X" is the Nominated EE Value that is confirmed through a PJM approved Post-Installation M&V Report divided by the Nominated EE value in the EE Modification for the planned energy efficiency resource.
- For existing external generation resources without firm transmission, the Credit Adjustment Factor will be zero if the Participant has demonstrated that firm transmission has been procured.
- For Planned generation resources, the Credit Adjustment Factor will be 0.5 (50%) if a full (not provisional) Interconnection Service Agreement has been successfully executed but Interconnection Service has not yet begun, and will be zero on or after the start date of Interconnection Service.
- For Qualifying Transmission Upgrades, the Credit Adjustment Factor will be 0.5 (50%) if a full (not provisional) Interconnection Service Agreement has been successfully executed but Interconnection Service has not yet begun, and will be zero on the date the Qualifying Transmission Upgrade is placed in service.
- PJM will consider credit adjustment factors other than these on a case-by-case basis.

If a Participant offers a Resource Requiring Credit for RPM into an RPM auction, but the Participant's RPM Credit Limit is insufficient for the participant's RPM Credit Requirement including the new offer, then the offer will be rejected. If the offer was made as part of a sell offer upload file (multiple resources offered simultaneously), then the entire file upload will be rejected. Previous offers made and accepted into an auction will not be rejected solely because a subsequent offer was rejected.

A participant that has procured capacity in an Incremental Auction may incur a change in credit requirement if the cost of the procured capacity differs from the cost of the originally-committed capacity.

4.8.3 Auction Credit Rate

An Auction Credit Rate is calculated prior to each RPM Auction for such Delivery Year:

- Prior to the posting of the BRA results, the RPM Credit Rate is equal to the greater of (i) $20/ MW-day or (ii) .3 * applicable Delivery Year's Net CONE for the RTO (in $/MW-day), times the number of days in the Delivery Year.
- Upon posting the BRA clearing results, the RPM Credit Rate used for planned resource commitments in the BRA is equal to the greater of (i) $20/MW-day or (ii) .2 times the Capacity Resource Clearing Price for the LDA and resource product type (i.e., limited, extended summer, and annual) that applies to the planned resource[8], times the number of days in the Delivery Year.
- For any planned resource not previously committed for a Delivery Year that participates in an Incremental Auction, the Auction Credit Rate is equal to the greater of (i) 0.3 times the applicable Delivery Year's Net CONE for the RTO or (ii) 0.24 times the Capacity Resource Clearing Price in the BRA for the applicable Delivery Year for the LDA and resource product type that applies to the planned resource or (iii) $20 per MW-day, times the number of days in the Delivery Year.
- Upon posting the results of an Incremental Auction, the Auction Credit Rate used for planned resources committed in the Incremental Auction is equal to the greater of (i) $20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price in such Incremental Auction for the LDA and resource product type that applies to the planned resource, but no greater than the pre-clearing Incremental Auction Credit Rate for such Incremental Auction times the number of days in the Delivery Year.
- One rate is calculated for each Auction, binding LDA, and resource product type, and applied according to the Auction, LDA, and resource product type in which the capacity was committed.

4.8.4 Credit-Limited Offers in RPM Auctions

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Seller electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement (i.e., Maximum Post-Auction Credit Exposure), in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the post-auction Auction Credit Rate; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Seller electing this alternative, the RPM Auction Credit Requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-

8 Resource product types are effective with the 2014/2015 Delivery Year.

Limited Offer (i.e., Maximum Post-Auction Credit Exposure), and the RPM Auction Credit Requirement subsequent to posting of the results will be the Auction Credit Rate times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The following business rules apply to Credit-Limited Offers:

- A supplier must notify PJM prior to the opening of the RPM Auction bidding window if they intend to submit a credit-limited offer.
- A Maximum Post-Auction Credit Exposure is assigned separately to each Planned Resource.
- The sum of the Maximum Post-Auction Credit Exposure nominated for each Planned Resource may not exceed the party's total available credit. Coupled Demand Resource Offers may not utilize the Credit Limited Offer functionality.

4.8.5 Price Responsive Demand Credit Requirement

A PRD Provider seeking to commit PRD in the Base Residual Auction, Third Incremental Auction, or the FRR Alternative, and for which there is a materially increased risk of non-performance for such PRD, must satisfy the Price Responsive Demand Credit Requirement prior to the deadline for submitting the PRD Plan.

The Price Responsive Demand Credit Requirement shall be based on the maximum Nominal PRD Value in the PRD Plan * Forecast Pool Requirement*Price Responsive Demand Credit Rate. For a PRD Provider, the maximum Nominal PRD Value in the PRD Plan may be reduced by the amount of existing PRD that is currently registered and approved in eLRS system by such PRD Provider on January 1 in advance of the PRD Plan submittal deadline.

Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.3 times Net Cone for the PJM Region for such Delivery Year or (ii) $20/MW-day) times the number of days in such Delivery Year.

After the posting of the Base Residual Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for price responsive demand committed in the Base Residual Auction or to the FRR Alternative, shall be the (greater of (i) $20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price for an Annual Resource in such auction for the LDA within the PRD load is located) times the number of days in the Delivery Year times a final price uncertainty factor of 1.05.

For any additional PRD that seeks to commit in a Third Incremental Auction or seeks to commit PRD be reduce the final unforced capacity obligation of an FRR Entity, the Price Responsive Demand Credit Rate shall be the same rate that is used after posting of the Base Residual Auction results.

After the posting of the Third Incremental Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for all Price Responsive Demand, shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Final Zonal Capacity Price for the zone in which the price responsive demand is located) times the number of days in such Delivery Year, but no greater than the post BRA Price Responsive Demand Credit Rate.

Section 5: RPM Auctions

Welcome to the RPM Auctions section of the PJM Manual for the Reliability Pricing Model. In this section, you will find the following information:

- An overview description of the RPM Auctions (see "Overview of the RPM Auctions")
- The auction timeline for RPM Auctions (see "RPM Auction Timeline")
- The auction parameters for the RPM Auctions (see "RPM Auction Parameters")
- The business rules for sell offers in RPM (see "Sell Offers in RPM")
- The business rules for buy bids in RPM (see "Buy Bids in RPM")
- The requirements to offer in the PJM Energy Market (see "Energy Market Offer Requirements")
- The business rules for the Base Residual Auction (see "Base Residual Auction")
- The business rules for the Incremental Auctions (see "Incremental Auctions")
- The business rules for the auction clearing results (see "Auction Clearing Results")
- An overview description of the reliability backstop mechanism (see "Reliability Backstop")

5.1 Overview of RPM Auctions

The Reliability Pricing Model (RPM) is a multi-auction structure designed to procure resource commitments to satisfy the region's unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

- *Base Residual Auction – The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.*
- *Incremental Auctions – Up to three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.*
  - *The First, Second, and Third Incremental Auctions* are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.
  - *A Conditional Incremental Auction* may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.
- *The Bilateral Market – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also*

provides LSEs the opportunity to hedge against the Locational Reliability Charge determined as a result of the RPM Auction process. The bilateral market is facilitated through the eRPM system.

5.2 RPM Auction Timeline

The following Auction timeline provides the deadline for key RPM activities:

RPM Activity	Deadline
Post Planning Parameters for BRA	February 1st prior to the Base Residual Auction *
Data Submittal (Avoidable Cost Data, Opportunity Cost, & Projected Market Revenues) to IMM if submitting non-zero sell offer price	120 days prior to commencement of offer period
IMM to notify Capacity Market Sellers of Market Seller Offer Caps	90 days prior to commencement of offer period
Submittal of Minimum Offer Price Rule (MOPR) exemption request	120 days prior to commencement of offer period
IMM to notify Capacity Market Seller of determination on MOPR exemption request	90 days prior to commencement of offer period
Submittal of must-offer exemption request	120 days prior to commencement of offer period
IMM to notify Capacity Market Seller of determination on must-offer exemption request	90 days prior to commencement of offer period
Submittal of request for alternative maximum EFORd	120 days prior to commencement of offer period
IMM provides determination on request for alternative maximum EFORd	90 days prior to commencement of offer period
Base Residual Auction	May, 3 years prior to the Delivery Year
Post Updated Planning Parameters for First Incremental Auction	1 Month prior to First Incremental Auction
First Incremental Auction	September, 20 months prior to the Delivery Year
Post Updated Planning Parameters for Second Incremental Auction	1 Month prior to Second Incremental Auction
Second Incremental Auction	July, 10 months prior to the Delivery Year
Final EFORd fixed for Delivery Year	By November 30th prior to the Delivery Year

RPM Activity	Deadline
Post Final Planning Parameters for Third Incremental Auction	1 Month prior to Third Incremental Auction
Third Incremental Auction	February, 3 months prior to the Delivery Year
Conditional Incremental Auction	As Needed

Exhibit 2: RPM Auction Timeline

5.3 RPM Auction Parameters

The following information shall be posted by PJM for each Base Residual Auction by February 1st prior to the commencement of the Base Residual Auction offer period:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Short Term Resource Procurement Target
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd
- Forecast Pool Requirement (FPR)
- Demand Resource (DR) Factor
- Reliability Requirements of the PJM Region and each modeled LDA
- Variable Resource Requirement (VRR) Curves of the PJM Region and each modeled LDA without FRR Entity adjustments. Adjusted VRR Curves with FRR Entity adjustments will be posted after FRR Capacity Plans are approved.
- CETO and CETL values for each modeled LDA
- Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements for the PJM Region and each Modeled LDA (for the 2014/2015 Delivery Year and beyond)
- Transmission Upgrades projected to be in service for the Delivery Year
- Bidding window schedule for the Base Residual Auction
- Cost of New Entry (CONE) for the PJM Region and each modeled LDA
- Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
- Auction Credit Rate
- For the Delivery Year 2012/2013 and beyond, the amount of unforced capacity to be procured by PJM due to increase in Reliability Requirement or the amount to be released from the commitment due to a reduction in Reliability Requirement will be posted one month prior to the First, Second, or Third Incremental Auctions. The

changes in the CETL values and the amount of unforced capacity to be procured for each LDA will be posted one month prior to an Incremental Auction.

5.3.1 Resource-Specific Sell Offer Requirements

Sell Offers for the Base Residual and Incremental Auctions must be submitted in PJM's eRPM system. Sell offers are only accepted during a fixed bidding window which is open for at least five (5) business days. The bidding window for a Base Residual Auction and Incremental Auctions will be posted on the PJM website. Sell offers may not be changed or withdrawn after the bidding window for a Base Residual Auction or Incremental Auction is closed.

The following are business rules that apply to Resource-Specific Sell Offers:

- The smallest increment that may be offered into any auction is 0.1 MW
- A resource-specific sell offer will specify, as appropriate:
- Specific Generating Unit or Demand Resource
- Effective with the 2014/2015 Delivery Year, a demand resource with the potential to qualify as two or more product types may submit separate but coupled Sell Offers for each product type for which it qualifies at different sell offer prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Separate resources will be modeled in the eRPM system for each product type. For coupled Sell Offers, the offer price of the Annual Demand Resource offer must be at least $.01/MW-day greater than the offer price of the coupled Extended Summer Demand Resource offer and the offer price of an Extended Summer Demand Resource must be at least $.01/MW-day greater than the offer price of the coupled Limited Demand Resource offer.
- Base Offer Segment minimum and maximum amount of installed capacity offered in MWs for the resource
- Base Offer Segment price willing to receive in $/MW-day (in UCAP terms)
- Regular Schedule, Self-Schedule or Flexible Self-Schedule flag
- EFORd to apply to the offered MWs (only applicable in the Base Residual Auction, First Incremental Auction, and Second Incremental Auction) for generation resources
- New Unit Pricing participation flag for generation resources
- The ICAP MW quantity specified in the Base Offer Segment will be converted into an UCAP MW quantity by the sell offer EFORd for use in the auction clearing. The sell offer price specified in the Base Offer Segment is in UCAP terms and will not be converted for use in the auction clearing.
- The Base Offer Segment may be offered as either a single price quantity for the capacity of the resource or divided into up to ten offer blocks with varying price-quantity pairs that represent various segments of capacity from the resource. The Base Offer Segment will consist of block segments at the specified price-quantity pairs.
- The seller specifies the EFORd to apply if participating in a Base Residual Auction, First Incremental Auction, or Second Incremental Auction.

- The EFORd cannot exceed the greater of the EFORd calculated based on outage data for 12 months ending September 30^{th} prior to the Base Residual Auction, the 5 Year Average EFORd based on outage data for 12 months ending September 30^{th} prior to the Base Residual Auction, or the EFORd submitted by the market participant in their Base Residual Auction Sell Offer.[9]
- The EFORd applied to the Third Incremental Auction will be determined by PJM using the forced outage data for the 12 months ending on September 30 prior to the Delivery Year.
- The seller is willing to accept the clearing of any amount equal to or greater than the minimum MW amount offered and equal to or less than the maximum MW offered.
- If the self-scheduled flag is enabled in the sell offer, the sell offer price must be set to zero and the minimum and maximum amounts specified in the sell offer must be equal.
- The acceptance of the sell offer is based on the party's Maximum Available ICAP Position at the opening of the auction's bidding window.
- If a participant has a positive Maximum Available ICAP Position, PJM only accepts a sell offer up to the Maximum Available ICAP Position.
- If a participant has a zero or negative Maximum Available ICAP Position, PJM will reject the sell offer.
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" as presented in the FRR Business Rules will be rejected.
- For Planned Resources and external resources without firm transmission, sell offers for which the RPM Credit Requirement exceeds the credit available will be rejected.
- All sell offers for a supplier that fails the Three-Pivotal Supplier Test will be capped within the mitigated LDA
- Cleared sell offers and offers receiving Make-Whole payments are binding commitments to provide capacity.

5.3.2 Flexible Self Scheduling

An LSE may specify offer segments as flexible self-scheduled in the Base Residual Auction to provide a mechanism to manage the quantity uncertainty related to the Variable Resource Requirement.

To specify a segment as a flexible self-scheduled segment, an LSE must specify the following:

- For each such segment, "flexible self-scheduled" must be selected as the offer type of the segment.
- A flexible self-schedule sell offer must specify an offer price that will be utilized in the market clearing in the event that the resource is not needed to cover the calculated

[9] Prior to March 27, 2009, the EFORd could not exceed the EFORd calculated based on outage data for 12 months ending September 30^{th} prior to the auction.

capacity obligation. This is in addition to the data required of a self-schedule resource-specific sell offer.

- In conjunction with an offer of a flexible self-schedule segment, the LSE must also submit through eRPM a percentage of the Preliminary Zonal Peak Load Forecast in each transmission zone the LSE wishes to cover with self-scheduled and flexible self-scheduled resources. This percentage of the peak load forecast will be used to calculate the LSE's resulting capacity obligation through the auction clearing process that considers the Variable Resource Requirement.

If the same LSE offers both self-scheduled and flexible self-schedule segments to serve an Unforced Capacity Obligation within the same LDA, those segments that are self-scheduled will be used first to meet the obligation. The flexible self-scheduled segments will be automatically cleared in the auction if they are needed to supply the LSEs resulting capacity obligation. In the event that the LSE does not need all of the segments that were specified as flexible self-scheduled to meet its resulting capacity obligation, the RPM clearing function will consider the excess as offered into the market at the price specified with the flexible self-scheduled segment. The segments that are considered excess for this LSE will be those that have the highest specified offer prices.

5.3.3 New Entry Pricing

New Entry Pricing is an incentive provided to Planned Generation Resources where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are capped. New Entry Pricing allows Planned Generation Resources to recover the amount of their cost of entry-based offer for up to two additional consecutive years under certain conditions.

New Entry Pricing is applicable under the following conditions:

(1) The new entry must select the New Entry Pricing option at the time the sell offer into the initial BRA (Delivery Year 1 BRA) is submitted

(2) The capacity cleared from the new entry (including any make-whole MW) in the Delivery Year 1 BRA would move the total LDA resources committed in the BRA from below the LDA Reliability Requirement to a MW quantity at or above the MW quantity at the price-quantity point on the VRR Curve where the price is 40% of the Net CONE divided by the quantity one minus pool-wide average EFORd.

(3) The seller submits offers into the two immediately following BRAs (Delivery Year 2 BRA and Delivery Year 3 BRA) to sell the entire capacity of the unit committed in the Delivery Year 1 BRA at a price equal to the lesser of (a) the price offered in the Delivery Year 1 BRA where the resource was classified as planned generation; or (b) 90% of the Net CONE applicable in the Delivery Year 1 BRA in UCAP basis.

(4) Failure to submit a sell offer consistent with condition (3) above in the Delivery Year 3 BRA shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a sell offer consistent with condition (3) in the Delivery Year 2 BRA shall make the resource ineligible for New Entry Price Adjustment for Delivery Years 2 and 3.

New entry revenues:

(1) If the new entry meets conditions (1) and (2) above and is the marginal offer t in Delivery Year 1 BRA, it sets the resource clearing price for the LDA in Delivery Year 1 BRA and receives revenues based on this price in the Delivery Year 1 BRA.

(2) If the new entry clears its capacity in either of the two subsequent BRAs (Delivery Year 2 BRA or Delivery Year 3 BRA), it will receive revenues based on the LDA clearing price in such subsequent year BRA.

(3) If the new entry does not clear in either of the two subsequent year BRAs (Delivery Year 2 BRA or Delivery Year 3 BRA), it will be resubmitted at the highest offer price at which the unforced MW amount cleared in the Delivery Year 1 BRA will clear in the subsequent year BRA (Delivery Year 2 BRA or Delivery Year 3 BRA). The resource clearing price and the resources cleared for such subsequent year BRA will be determined from the clearing with the resubmitted sell offer. The new entry shall clear in such subsequent year BRA and be committed in the amount cleared plus any additional make-whole MW from its Sell Offer for such subsequent year BRA, but such make-whole MWs shall not be greater than the make-whole MWs committed in the Delivery Year 1 BRA. The new entry will receive revenues for the entire committed quantity in such subsequent year BRA based on the sell offer price initially submitted for such subsequent year BRA. The difference between the initially submitted sell offer price and the clearing price in such subsequent year BRA and any difference between cleared quantity and committed quantity in such subsequent year BRA will be paid as Resource Make-Whole payments to the new entry. The other capacity resources that clear such subsequent year BRA will receive the clearing price for such subsequent year BRA.

While the New Entry Pricing is effective, the LDA in which the New Entry was cleared will be modeled as an LDA in Years 2 and 3 regardless of the amount of LDA Capacity Emergency Transfer Limit margin over Capacity Emergency Transfer Objective in the PJM RTEP Process. After the New Entry Pricing period, the LDA will be maintained only if deemed necessary in the PJM RTEP Process.

Market Monitor's existing authority and review responsibilities shall include "New Entry Pricing." Market Monitor shall analyze and report on "New Entry Pricing" in the State of the Market Report.

5.3.4 Sell Offer Caps

Submission of the Avoidable Cost Rate (ACR) Data

- 120 days prior to the commencement of the offer period for the auction, participants must submit the data specified in ***Section 6.7 of Attachment DD of the Open Access Transmission Tariff*** in order to submit a non-zero Sell Offer in the Base Residual Auction.
- Capacity resource owners must supply PJM with their avoidable cost data through the RPM Avoidable Cost Rate (ACR) System.

- The avoidable cost calculation is based on the categories of cost that are specified in ***Section 6.8 of Attachment DD of the Open Access Transmission Tariff.*** The calculation should be based on the annual costs that would be avoidable assuming the unit would otherwise retire.
- Where multiple units exist at a single plant, the plant's total avoidable costs shall be allocated to each individual unit in an appropriate manner. The sum of such costs assigned to each unit shall equal the total plant costs.
- The avoidable cost data should be for the 12 months preceding the month in which the data must be provided.
- For units that are jointly-owned, only one owner, typically the operator is expected to provide avoidable cost data and Projected PJM Market Revenues for the unit.
- All joint-owners of a unit can input their own bilateral revenues/costs, opportunity costs and transition adder.
- If a unit is not expected to be operational during the Delivery Year, no avoidable cost and opportunity cost data are required, but notice of status is required.

Calculation of Sell Offer Caps

- Sell offer caps shall be calculated as specified in Section 6.4 of Attachment DD of the Open Access Transmission Tariff.
- If a unit does not submit ACR data, specify an opportunity cost, default rate, or specify a transition adder in the RPM ACR System, the offer cap for that unit will be set to the applicable default rate.
- If no Projected PJM Market Revenues are submitted for a unit by a capacity resource owner, then PJM will use its own calculation of PJM Market Revenues in calculating the Sell Offer Cap of a unit.
- Sell Offer Cap(s) will be calculated by Market Participant, by unit, by segment.
- 90 days prior to the commencement of the offer period, the IMM shall calculate and notify the Capacity Market Seller of their Sell Offer Cap consistent with Section 6 of Attachment DD of the Open Access Transmission Tariff. All unforced capacity of all existing Generation Capacity Resources shall be offered in the Base Residual Auction unless one of the following conditions is met:
- The resource is reasonably expected to be physically unable to participate in the relevant Delivery Year. The resource has a financially and physically firm commitment to an external sale of its capacity. The resource was interconnected to the Transmission System as an Energy Resource and not converted to a Capacity Resource.
- No offer caps are applied to sell offers of Planned Generation Resources.
- No offer caps are applied to sell offers of Demand Resources or Planned Energy Efficiency Resources.
- For the purposes of offer capping in the RPM Auctions, a resource not yet in operation shall be considered a planned resource for only the first RPM Auction that its' offer is cleared. The resource is considered an Existing Resource, for the

purposes of offer capping, for any subsequent Auction except in the case of New Entry Pricing.

5.3.5 Minimum Offer Price Rule (MOPR)

The Minimum Offer Price Rule (MOPR) of Section 5.14(h) of Attachment DD of the PJM OATT applies to sell offers of certain planned generation capacity resources including planned upgrades of existing generation capacity resources. The MOPR does not apply to sell offers based on nuclear, coal, integrated gasification combined cycle, hydroelectric, wind or solar facilities. Also, the MOPR applies only to resources located in an LDA for which a separate VRR Curve is established and is applicable until the resource clears an RPM auction. For each Delivery Year, PJM determines the Net Cost of New Entry (CONE) for a combustion turbine generator and for a combined cycle generator. Unless a MOPR exception is requested and approved according to the process and timelines described below, a sell offer submitted in any BRA or Incremental Auction that is less than 90% of the applicable Net CONE shall be set equal to 90% of the applicable Net CONE. If there is no otherwise applicable asset class as described above and the sell offer is less than 70% of the Net CONE for a combustion turbine generator then the sell offer shall be set equal to 70% of the Net CONE for a combustion turbine generator.

A sell offer below the MOPR screen price shall be permitted and not be re-set if the capacity market seller obtains a determination from PJM prior to the RPM Auction that the seller offer is permissible because the offer is consistent with the competitive, cost-based, fixed net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. A capacity market seller wishing to offer below the MOPR screen price may request such a determination according to the MOPR exception process described below.

1) MOPR Exception Process Timelines

    a. Requests for exceptions must be submitted no later than 120 days prior to the commencement of the offer period of an RPM auction. Requests must provide all relevant information and are submitted to both the IMM and PJM

    b. The IMM has 30 days from receipt of the request to make a determination regarding the exceptions and report its findings to the seller requesting the exception and PJM.

    c. If the seller does not agree with the IMM findings it may appeal to PJM to review its request for exception

    d. PJM has 55 days from the receipt of the exception request to notify the seller of its determination regarding the exception request. (25 days following the IMM determination)

2) Documentation Required in MOPR Exception Request

    The capacity market seller must include in its request for an exception documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as offsetting net revenues. The requests must include a certification, signed by an officer of the capacity market seller, that the claimed costs accurately reflect the seller's reasonable expected costs of new entry and that the request satisfies all standards for an exception. Supporting documentation of for project costs may include, as applicable and available, the following:

- a complete project description;
- environmental permits;
- vendor quotes for plant or equipment;
- evidence of actual costs of recent comparable projects;
- bases for electric and gas interconnection costs and any cost contingencies;
- bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs;
- financing documents for construction--period and permanent financing or evidence of recent debt costs of the seller for comparable investments;
- the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling; and
- identification and support for any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer.

The request also shall include all revenue sources relied upon in the sell offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period. In making such demonstration, the capacity market seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to PJM and the IMM. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. The capacity market seller shall provide any additional supporting information requested by PJM or the IMM to evaluate the sell offer.

An evaluated sell offer shall be permitted if the information provided reasonably demonstrates that the sell offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the capacity market seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM to develop the minimum offer level. Capacity market sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the capacity market seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable PJM to make a determination will result in denial of an exception by PJM.

5.3.6 Qualified Transmission Upgrade Sell Offer Requirements

A Qualifying Transmission Upgrade sell offer will specify, as appropriate:

- Increase in CETL provided by the upgrade (maximum MW, as certified by PJM Transmission Planning Department)
- Minimum MW offered (min = max for upgrades that involve a single equipment upgrade, min could be less than max where participant is proposing multiple upgrades or upgrades to several pieces of equipment)
- Source and sink LDAs associated with the upgrade
- Price willing to receive for each segment in $/MW-day specified as the price difference between the sink LDA price and the source LDA price

The increase in CETL provided by a Qualifying Transmission Upgrade must be certified by PJM at least 45 days prior to the Base Residual Auction.

Cleared sell offers and offers receiving Make-Whole payments are binding commitments to provide capacity.

5.4 Buy Bids in RPM

Buy Bids for the Incremental Auctions must be submitted in PJM's eRPM system. Buy Bids are only accepted during a fixed bidding window which is open for at least five (5) business days. Buy Bids may not be changed or withdrawn after the bidding window for an Incremental Auction is closed.

A Buy Bid must specify:

- Quantify of unforced capacity resources desired, in increments of 0.1 MWs;
- Maximum price willing to pay for unforced capacity resources in $/MW-day;
- Type of unforced capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource (for 2014/2015 and beyond);
- Desired location (Locational Deliverability Area) for the replacement capacity.

Buy Bids may not specify a minimum MW amount. The Buy Bid may clear any MW amount equal to or less than the quantity of unforced capacity resources desired in the Buy Bid.

In the event of a delay or cancellation of a Qualifying Transmission Upgrade, the Buy Bid will specify the purchase of capacity resources in the LDA for which the Qualifying Transmission Upgrade was to increase the CETL (Sink LDA).

Cleared Buy Bids are binding commitments to purchase capacity.

5.5 Energy Market Offer Requirements

All generation resources that have an RPM Resource Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources that have an RPM Resource Commitment must be registered in the Full Program Option of the Emergency Load Response Program and thus available for dispatch during PJM-declared emergency events. Please refer to the ***Manual for Scheduling Operations (M-11)*** for details on PJM Energy Market participation.

5.6 Base Residual Auction

The Reliability Pricing Model includes a single Base Residual Auction for each Delivery Year. A Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Base Residual Auctions are conducted in accordance with the auction schedule posted on the PJM website.

5.6.1 Participation in the Base Residual Auction

Products that resource providers can offer into PJM's Base Residual Auction include:

- Existing generation
- Planned generation
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources
- Qualifying Transmission Upgrades

Existing Generation in a party's RPM Resource Portfolio that have available capacity to offer and are not offered into the Base Residual Auction for the Delivery Year shall be excluded from participation in any and all Incremental Auctions conducted for the Delivery Year. Generation is treated as existing when the generation is (a) in service at the commencement of the Base Residual Auction or (b) not yet in service but has cleared in an RPM Auction for any prior Delivery Year. These unoffered MWs from existing generation resources shall be ineligible to serve as capacity resources on behalf of any RPM entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts for generation and demand resources.

The following are business rules that apply to the Base Residual Auction:

- Existing generation, existing Demand Resources, and Energy Efficiency Resources that have CAP MOD, DR MOD, or EE MOD increases that are approved after the Base Residual Auction are eligible to offer the capacity increase into an Incremental Auction for the Delivery Year if the CAP MOD, DR MOD, or EE MOD increase is approved prior to the opening of the Incremental Auction bidding window.
- For the Base Residual Auction, a party's Current, Minimum and Maximum Available ICAP Position for a specific unit are equal to the minimum of (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for the Delivery Year.

$$AvailICAPPosition_{for\,a\,unit} = MinimumDailyValue_{for\,DY}(DailyICAPOwned - DailyFRRCapPlanCommitments)$$

- For the Base Residual Auction, a party's Available ICAP Position for a demand resource is equal to the minimum of (Daily Nominated DR Value – Daily FRR Capacity Plan Commitments) for the Delivery Year.

$$AvailICAPPosition_{DR} = MinDailyValue_{forDY}(DailyNomDRValue - DailyFRRCapPlanCommitments)$$

- Following a Base Residual Auction, a party's Daily Unoffered ICAP for a generation resource or demand resource is calculated and is equal to the Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$DailyUnofferedICAP_{GenorDR} = AvailICAPPosition - OfferedICAP$$

- Resources may be directly offered into the Base Residual Auction by specifying a MW quantity and sell offer price in the sell offer or may be self-scheduled into the Base Residual Auction by enabling the self-schedule flag in the sell offer. See the Resource-Specific Sell Offer Requirements Section for further details.
- The product offered in the Base Residual Auction must be resource-specific or apply to a Qualifying Transmission Upgrade.
- The smallest increment that may be offered into a Base Residual Auction is 0.1 MW.

5.6.2 Auction Clearing Mechanism – Base Residual Auction

The Base Residual Auction clearing software is an optimization algorithm. This algorithm has the objective of minimizing capacity procurement costs given the supply offers, Variable Resource Requirement Curve(s), Locational Constraints, and starting with June 1, 2014, the Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements . All self-scheduled resources in the Base Residual Auction will automatically clear at their maximum MW amount specified in the sell offer. The Base Residual Auction clearing price for each LDA is determined by the optimization algorithm. The Resource Clearing Price within each LDA is the sum of:

- The marginal value of system capacity and
- Annual Resource Price Adder, if any, and
- Extended Summer Price Adder, if any, and
- Locational Price Adder(s), if any, relevant to such LDA.

The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Price Adder is applicable for Annual Resources and Extended Summer DR.

In the event that the Sell Offers forming the supply curve do not result in an intersection with the Variable Resource Requirement Curve, the marginal value of system capacity will be set along the Variable Resource Requirement Curve by extending the supply curve vertically from its end point until it intersects the Variable Resource Requirement Curve.

5.6.3 Resource Make-Whole Payments in the Base Residual Auction

Only the resource provider that offered and cleared fewer MWs than the minimum MW specification in the Base Residual Auction would receive a Resource Make-whole payment.

The Resource Make-whole Payment is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the Base Residual Auction.

$$ResourceMakewholePayment = ResourceClearingPrice \times (SellOfferMinMW - ClearedMW_{BRA})$$

Make-whole payments required in the BRA will be charged to all LSEs in the LDA via the Final Zonal Capacity Price.

Only cleared Qualifying Transmission Upgrades, cleared resource-specific sell offers, and cleared flexible self-scheduled offers in excess of their self-scheduled quantity are eligible for make-whole payments in the BRA.

5.6.4 Posting of Base Residual Auction Results

Base Residual Auction results are posted to a participant's eRPM account and summary results are posted to a public portion of the PJM website. For any Base Residual Auction, clearing results will not be posted until after 4 p.m. EPT on Friday of Auction Clearing week

Participants can view the resolution of their sell offer in the BRA through eRPM. The results of their sell offer will be categorized as cleared, uncleared, offered, unoffered, or make-whole.

Base Residual Auction sales are credited monthly during the Delivery Year as the unforced capacity is actually utilized.

5.7 Incremental Auctions

Effective 2012/13 Delivery Year:

- *The First, Second, and Third Incremental Auctions* are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.
- *A Conditional Incremental Auction* may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

5.7.1 Participation in the Incremental Auctions

Existing generation in a party's RPM Resource Portfolio that have available capacity to offer and are not offered into an Incremental Auction for the Delivery Year shall be excluded from participation in any subsequent Incremental Auctions conducted for the Delivery Year. Generation is treated as existing when the generation is (a) in service at the commencement of the Incremental Auction or (b) not yet in service but has cleared an RPM Auction for any prior Delivery Year. These unoffered MWs from existing generation shall be ineligible to serve as capacity resources on behalf of any entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts of generation and demand resources.

Products that resource providers can offer into an Incremental Auction include:

- Existing generation that was offered and not cleared in a prior auction for the same Delivery Year
- Planned generation

- Existing Demand Resources or Energy Efficiency Resources that were offered and not cleared in a prior auction for the same Delivery Year
- Planned Demand Resources or Energy Efficiency Resources
- Transmission upgrades are not eligible to be offered into Incremental Auctions. (*Transmission upgrades are only eligible to be offered into Base Residual Auction*)

The following are business rules that apply to the Incremental Auctions:

- The product offered in the Incremental Auction must be resource-specific.
- The smallest increment that may be offered into an Incremental Auction is 0.1 MW.
- Planned generation Planned Demand Resources, or Energy Efficiency Resources that were not eligible to participate at the time of the Base Residual Auction or prior Incremental Auction, are eligible to participate in subsequent Incremental Auctions if the planned generation, Planned Demand Resource, or Energy Efficiency Resource meets the requirements specified in Section 4 of this manual.
- Existing generation and existing Demand Resources or Energy Efficiency Resources that have CAP MOD increases, DR MOD increases, or EE MOD increases that are provisionally approved or approved after an Incremental Auction are eligible to offer the capacity increase into a subsequent Incremental Auction for the Delivery Year if the CAP MOD, DR MOD, or EE MOD increase is provisionally approved or approved prior to the opening of the subsequent Incremental Auction bidding window.
- For Incremental Auctions, a Current Available ICAP Position, Minimum Available ICAP Position, and Maximum Available ICAP Position are calculated.

A party's Current Available ICAP Position on a unit for an Incremental Auction is equal to the minimum Daily Available ICAP for such unit during the Delivery Year.

$$CurrentAvailableICAPPosition_{unit} = Min(DailyAvailableICAP)$$

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP – (Daily RPM Resource Commitments/(1-Effective EFORd)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP = DailyICAPOwned - DailyUnofferedICAP - \left(\frac{DailyRPMResourceCommitments}{1 - EffectiveEFORd}\right) - DailyFRRCapacityPlanCommitments$$

A party's Minimum Available ICAP Position represents the minimum amount that must be offered into an RPM Auction. A party's Minimum Available ICAP Position on a unit for an RPM Auction is equal to the *minimum* Daily Minimum Available ICAP for such unit during the Delivery Year.

$$MinimumAvailableICAPPosition_{unit} = Min(DailyMinAvailableICAP)$$

A party's Daily Minimum Available ICAP is equal to Daily ICAP Owned minus the Daily Unoffered ICAP minus Daily Cleared ICAP in RPM Auctions minus Daily FRR Capacity Plan Commitments. Daily Cleared UCAP in RPM Auctions is converted to Daily Cleared ICAP using the greater of the EFORd $_{1\,yr}$ at the time of the Base Residual Auction, EFORd $_{5\,yr}$ at the time of the Base Residual Auction, or the party's Sell Offer EFORd from the Base Residual Auction.

$$\text{DailyMinAvailableICAP} = DailyICAPOwned - DailyUnofferedICAP - \left[\frac{DailyClearedUCAP}{(1 - Max(\text{BRA EFORd 1yr, BRA EFORd 5yr, BRA SellOfferEFORd}))}\right] - DailyFRRCapacityPlanCommitments$$

A party's Maximum Available ICAP Position represents the maximum amount that a participant may offer into an RPM Auction. A party's Maximum Available ICAP Position on a unit for an RPM Auction is equal to the *minimum* Daily Maximum Available ICAP for such unit during the Delivery Year.

$$MaximumAvailableICAPPosition_{unit} = Min(DailyMaxAvailableICAP)$$

A party's Daily Maximum Available ICAP is equal to Daily ICAP Owned minus the Daily Unoffered ICAP minus Daily Cleared ICAP in RPM Auctions minus Daily FRR Capacity Plan Commitments. Daily Cleared UCAP in RPM Auctions is converted to Daily Cleared ICAP using a zero EFORd.

$$\text{DailyMaxAvailableICAP} = DailyICAPOwned - DailyUnofferedICAP - \left[\frac{DailyClearedUCAP}{(1-0))}\right] - DailyFRRCapacityPlanCommitments$$

For the Third Incremental Auction, a party's Minimum Available ICAP Position and Maximum Available ICAP Position for a unit will be equal to the party's Current Available ICAP Position for such unit.

A party's Daily Unoffered ICAP for a specific unit is calculated by adding the sum of any Daily Unoffered ICAP for such unit in prior RPM Auctions to Daily Unoffered ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

$$DailyUnofferedICAP_{\text{GenResource}} = \sum(DailyUnofferedICAP_{\text{fromPriorRPMAuctions}} + UnofferedICAPBilateralSales/Purchases)$$

For an Incremental Auction, a party's Daily Unoffered ICAP for generation resource is equal to the Minimum Available ICAP Position minus the Offered ICAP in the party's sell offer.

$$DailyUnofferedICAP_{\text{Gen}} = MinimumAvailableICAPPosition - OfferedICAP$$

For an Incremental Auction, the party's Available ICAP Position for a specific demand resource is equal to the minimum Daily Available ICAP for such demand resource during the Delivery Year.

$$AvailableICAPPosition_{\text{Demand Resource}} = Min(DailyAvailableICAP)$$

The Daily Available ICAP for a specific demand resource is equal the resource's Daily Nominated DR Value – Daily Unoffered ICAP - ((Daily RPM Resource Commitments/(DR Factor *Forecast Pool Requirement)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP_{\text{DR}} = DailyNominated\ DRValue - Daily\ Unoffered\ ICAP - (\frac{Daily\ RPM\ Resource\ Commitments}{DRFactor \times FPR}) - DailyFRRCapPlanCommitments$$

A party's Daily Unoffered ICAP for a specific demand resource is calculated by adding the sum of any Daily Unoffered ICAP for such demand resource in prior RPM Auctions.

For an Incremental Auction, a party's Daily Unoffered ICAP for a demand resource is equal to the Available ICAP Position for the demand resource minus the Offered ICAP in the party's sell offer.

$$DailyUnofferedICAP_{DR} = AvailableICAPPosition - OfferedICAP$$

5.7.2 Timing of the Incremental Auctions

The First Incremental Auction is held during the month of September, twenty (20) months prior to the start of the Delivery Year.

The Second Incremental Auction is held during the month of July, ten (10) months prior to the start of the Delivery Year.

The Third Incremental Auction is held during the month of February, three (3) months prior to the start of the Delivery Year.

Incremental Auctions are conducted in accordance with the auction schedule posted on the PJM website.

5.7.3 Resource Make-Whole Payments in Incremental Auctions

Only the resource provider that offered and cleared fewer MWs than its minimum MW specification in an RPM Auction would receive a resource make-whole payment. This situation occurs because of the minimum MW specification in the sell offer data. This can occur at most for one resource in each LDA and for a one resource in the unconstrained market region.

The Resource Make-whole Payment is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the Auction. Make-whole payments required in the Auction will be charged to all cleared buy bids on pro-rata basis based on the MWs cleared in such auction. Only cleared resource-specific sell offers are eligible for make-whole payments in an Incremental Auction.

Make-whole charges assessed to buy bids cleared by PJM will be assessed to LSEs in the LDA via the Final Zonal Capacity Price.

5.7.4 Allocation of Costs in Incremental Auctions

The costs of the incremental commitments that are cleared in Incremental Auctions are allocated to resource providers that cleared Buy Bids in that Incremental Auction based on the cleared Buy Bid MW quantity and the clearing price and to LSEs by adjusting the Zonal Capacity Price.

5.7.5 Auction Clearing Mechanism – Incremental Auctions

The clearing of the Incremental Auctions is determined by the intersection of the supply curve and the demand curve. In the event the Sell Offers forming the supply curve do not intersect with the Buy Bids forming the demand curve, one of the following will occur:

(1) The clearing will be set along the demand curve by extending the supply curve vertically upward from its end point unit it intersects the demand curve, or

(2) The clearing will be set along the supply curve by extending the demand curve vertically downward from its end point until it intersects the supply curve, or

If no intersections occur as a result of the supply curve extension or the demand curve extension, no capacity will be cleared in the Incremental Auction. The Incremental Auction clearing prices for each Buy Bid or Sell Offer cleared is determined by the same optimization algorithm used in the Base Residual Auction clearing. The Resource Clearing Price within an LDA is equal to the sum of:

- The marginal value of system capacity and
- Annual Resource Price Adder, if any, and
- Extended Summer Price Adder, if any, and
- The Locational Price Adder(s), if any relevant for such LDA.

The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Price Adder is applicable for Annual Resources and Extended Summer DR.

The First, Second, and Third Incremental Auction clearing software is an optimization algorithm. The algorithm has the objective of minimizing the cost of committing capacity for the submitted Buy Bids given the Locational Constraints, Minimum Annual Resource Requirements, Minimum Extended Summer Resource Requirements and submitted supply offers.

5.7.6 Posting of Incremental Auction Results

The Incremental Auction results are posted to a participant's eRPM account and summary results are posted to a public portion of the PJM website. For any Incremental Auction, clearing results will not be posted until after 4 p.m. EPT on Friday of Auction Clearing week.

Participants may view the resolution of their sell offer in the Incremental Auction through eRPM. The results of their sell offer will be categorized as cleared, offered, unoffered, or make-whole.

Incremental Auction purchases/sales are charged/credited monthly during the Delivery Year.

5.8 Auction Clearing Results

5.8.1 Zonal Capacity Prices

Zonal Capacity Prices for a Delivery Year are calculated following the Base Residual Auction for the Delivery Year and are adjusted following each Incremental Auction for the Delivery Year.

Preliminary Zonal Capacity Prices are calculated and posted following the Base Residual Auction for each Delivery Year. The Preliminary Zonal Capacity Price for each Zone is the sum of:

(1) The marginal value of system capacity for the PJM Region;

(2) The Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA);

(3) An adjustment, if any, to account for adders paid to Annual Resources and Extended Summer DR in the LDA for which the zone is located (effective for the 2014/2015 Delivery Year); and

(4) An adjustment in the Zone, if required, to account for any resource make-whole payments.

Make-whole payments are allocated to the entire obligation associated with the area in which the resource is cleared. If the resource clears in the unconstrained area, the make-whole payment is allocated to the entire RTO obligation. If the resource that is made whole clears in located in a constrained LDA, the make-whole payment is allocated to the entire obligation of the constrained LDA.

The following are business rules that apply to the Preliminary Zonal Capacity Prices:

- The Weighted Zonal Capacity Price for a Zone that includes multiple non-overlapping LDAs is the weighted average of the Zonal Capacity Prices for such LDAs, weighted by the Unforced Capacity of Resources Cleared (including Make whole MW) in each such LDA. If the Zone has a smaller LDA within a larger LDA then the Weighted Zonal Capacity Price is calculated using the smaller LDA and the remaining portion of the larger LDA.
- The Locational Price Adder is an addition to the marginal value of unforced capacity within an LDA as necessary to reflect the price of resources required to relieve the applicable binding locational constraints.
- A Locational Price Adder shall not be a negative number.

Preliminary Zonal Capacity Prices for the Delivery Year are posted by PJM at the end of the Base Residual Auction clearing process.

- Zonal Capacity Prices for a Delivery Year are adjusted following each Incremental Auction for the Delivery Year.
- The Adjusted Zonal Capacity Prices for each Zone is the sum of:

  (1) The average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity);

(2) The average Locational Price Adder, if any, weighted by the Unforced Capacity cleared in all auctions previously conducted for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity);

(3) An adjustment, if any, to account for adders paid to Annual Resources and Extended Summer DR for all auctions previously conducted for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); and

(4) An adjustment, if required, to account for any resource make-whole payments for all auctions previously conducted for the Delivery Year (excluding any resource make-whole payments to be charged to the buyers of replacement capacity).

Adjusted Zonal Capacity Prices for the Delivery Year are posted following each Incremental Auction for that Delivery Year.

The Final Zonal Capacity Prices reflect the final price adjustments that are necessary to account for potential decreases in RPM Auction Credits to existing demand resources that were granted relief from Capacity Resource Deficiency Charges due to permanent departure of load.

The Final Zonal Capacity Prices are calculated such that the total amount of credit for CTR holders, Incremental CTR Holders, resources cleared for LSEs in all RPM Auctions for a given Delivery Year, Qualifying Transmission Upgrades cleared in the Base Residual Auction, and by LSEs serving load that is committed as price responsive demand for the Delivery Year equals to the total amount of Locational Reliability Charges assessed to loads. The Final Zonal Capacity Price is not net of the Final Zonal CTR Credit Rate.

The ***Final Zonal Capacity Prices*** for the Delivery Year are posted by PJM following the Third Incremental Auction for that Delivery Year.

5.8.3 CTR Credit Rates

The Base Zonal CTR Credit Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of the Base Residual Auction divided by the Base Zonal UCAP Obligation.

$$BaseZonalCTRCreditRate_{(\$/mw - Day)} = \frac{EconomicValueofCTRs_{AllocatedtoLSEsinBRA}}{ZonalUCAPObligation}$$

The ***Base Zonal CTR Credit Rate*** is posted with the Base Residual Auction results.

The Final Zonal CTR Credit Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of all RPM Auctions for the Delivery Year divided by the Final Zonal UCAP Obligation.

$$FinalZonalCTRCreditRate(\$/MW - day) = \frac{EconomicValueofCTRs_{AllocatedtoLSEsin\ all\ RPM\ Auctions}}{FinalZonalUCAPObligation}$$

The Final Zonal CTR Credit Rates are posted by PJM with the Third Incremental Auction clearing results.

5.8.4 CTR Settlement Rates

The CTR Settlement Rate ($/MW-day) is equal to the total Economic Value of CTRs ($/day) allocated to LSEs in a zone for all LDAs in which the zone resides as a result of all RPM Auctions for a Delivery Year divided by the maximum of the LDA CTR MWs allocated to LSEs in a zone.

$$CTRSettlementRate_{(\$/MW - day)} = \frac{EconomicValueofCTRs_{AllocatedtoLSEs\ as\ a\ result\ of\ all\ RPM\ Auctions}}{MaximumLDACTRMWs_{AllocatedtoLSEs}}$$

The CTR Settlement Rates are posted by PJM with the Third Incremental Auction clearing results.

5.9 Reliability Backstop

The Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by:

- Lack of sufficient capacity committed through the RPM Auctions or
- Near-term transmission deliverability violations identified after the Base Residual Auction is conducted

The purpose of the Reliability Backstop is to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The Reliability Backstop mechanism is based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources committed as a result of the RPM Auctions.

Details on the Reliability Backstop, including the triggering conditions and auction clearing procedures, can be found in ***Section 16 of Attachment DD of the Open Access Transmission Tariff.***

Section 6: Capacity Transfer Rights

Welcome to the *Capacity Transfer Rights* section of the PJM Manual for the *Capacity Market*. In this section, you will find the following information:

- The definition and purpose of Capacity Transfer Rights (see "Definition and Purpose of Capacity Transfer Rights")
- The business rules for determining Capacity Transfer Rights (see "Determination of Capacity Transfer Rights"
- The business rules for allocation of Capacity Transfer Rights (see "Allocation of Capacity Transfer Rights")
- The business rules for determining Capacity Transfer Right credits (see "Capacity Transfer Rights Credits")
- The business rules for transferring Capacity Transfer Rights (see "Capacity Transfer Rights Transfer")

6.1 Definition and Purpose of Capacity Transfer Rights

The purpose of Capacity Transfer Rights is to allocate the economic value of transmission import capability that exists into a constrained LDA to holders of Capacity Transfer Rights. Therefore, Capacity Transfer Rights serve to offset a portion of the Locational Price Adder charged to load in constrained LDAs.

As explained in Sections 3 and 4 constrained Locational Deliverability Areas (LDAs) are modeled with their own VRR curves in the auction clearing process. The transmission import capability limit into a constrained LDA would require clearing resources with higher offer prices in the LDA (but at less than the prices on the LDA VRR Curve) to achieve the highest possible reliability in the LDA. This process would typically result in a price separation with LDA clearing price being higher than the unconstrained RTO clearing price. The Zonal Capacity Prices calculated in the constrained LDA would also be higher as they are a function of this higher clearing price. LSE Locational Reliability Charge in a zone is the LSE unforced capacity obligation multiplied by the Zonal Capacity Price. However, part of the LSE unforced capacity obligation is met by imported resources that receive auction credits at a lower price than the LDA clearing price. The credit to account for these lower-priced imported resources is achieved by allocating Capacity Transfer Rights (CTRs) to LSEs. CTRs would amount to dollar credits that would reduce the LSE load charges.

It is important to note that the LDA Reliability Requirement (based on the internal generation and CETO) used in the clearing process is typically higher than the unforced capacity obligation (based on coincident peak load) used for load charges and the CTR determination. Since the concept of CTRs is to provide credit towards the portion of the obligation met by imported resources, CTRs are calculated as the difference between the zonal (LDA) unforced capacity obligation and the unforced capacity cleared in the zone (LDA) plus the Short-Term Resource Procurement Target. The total CTRs are typically lower than the LDA import capability (CETL) while the CETL is fully utilized in meeting the LDA Reliability Requirement and calculating the LDA clearing price. LSEs in the constrained LDA benefit when the CETL into the LDA is increased by transmission upgrades.

A transmission upgrade may be funded by a New Service Customer (or, for facilities or upgrades in PJM queue prior to March 1, 2007 to an Interconnection customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade. In this case, the customer is allocated Incremental CTRs (Participant-Funded Project ICTRs). Alternately, a transmission upgrade may be offered as a Qualified Transmission Upgrade (QTU) in the Base Residual Auction. A cleared QTU will receive auction credits.

Incremental Capacity Transfer Rights (ICTRs) associated with Regional Facilities and Necessary Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements will be allocated to Responsible Customers to whom the costs of the Regional Facilities and Necessary Lower Voltage Facilities are assigned. Effective with the 2013/2014 Delivery Year, ICTRs associated with Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements will also be allocated to Responsible Customers to whom the costs of the Lower Voltage Facilities are assigned. Incremental Rights-Eligible Required Transmission Enhancements are Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Scheduled 12 of the Tariff) and meet one of the following criteria: (1) cost responsibility assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

In these cases the total CTRs are reduced to provide credits to these parties before distributing the CTRs to LSEs.

6.1.1 Capacity Transfer Rights

The following are business rules that apply to Capacity Transfer Rights:

- Capacity Transfer Rights are applicable only for the Delivery Year for which they were defined.
- *Capacity Transfer Rights are specified to the nearest 0.1 MW.*
- The total amount of Capacity Transfer Rights that are allocated to LSEs in an LDA are equal to the amount of unforced capacity imported into such LDA based on the results of the Base Residual Auction and all Incremental Auctions for such Delivery Year less [the Participant-Funded ICTRs and Incremental Rights-Eligible Required Transmission Enhancements ICTRs that are allocated into the LDA for the Delivery Year less the amount of import capability increase into the LDA attributed to Qualifying Transmission Upgrades for the Delivery Year]. Capacity Transfer Rights (CTRs) will be allocated in MWs for each modeled LDA in which the RPM Auctions for the Delivery Year resulted in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA.
- The economic value (in $/day) of Capacity Transfer Rights in an LDA as a result of all RPM Auctions for the Delivery Year is equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the MW quantity of CTRs allocated to LSEs in the LDA. The total economic value (in $/day) of Capacity Transfer Rights to LSEs in a zone is the sum of the economic values of Capacity Rights in an LDA for all LDAs in which such zone resides.

6.1.2 Participant-Funded Project Incremental Capacity Transfer Rights

Incremental Capacity Transfer Rights (ICTRs) are allocated to a New Service Customer (or, for facilities or upgrades in PJM queue prior to March 1, 2007 to an Interconnection customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade, to the extent such upgrade or facility increases the import capability into an LDA. Such incremental Capacity Transfer Rights allocation is based on the incremental increase in import capability across a Locational Constraint that is caused by the transmission facility upgrade.

Incremental Capacity Transfer Rights will be effective for thirty years or the life of the facility or upgrade, whichever is less. Under conditions when the internal resources cleared in the LDA are high, the total amount of Capacity Transfer Rights is limited. The Incremental Capacity Transfer Rights will be limited to the total amount of Capacity Transfer Rights.

If a customer funds advancement of a network transmission upgrade, the customer will receive Incremental CTRs for the years the upgrade is advanced based on the incremental CETL into a constrained LDA as certified by PJM. The customer should request PJM to certify the Incremental CTRs due to an advancement of a network transmission upgrade at least 90 days prior to the Base Residual Auction.

Participants must request PJM to certify the Incremental CTRs into the constrained LDAs modeled in RPM at least 90 days prior to the Base Residual Auction. PJM will certify the Incremental CTRs into the constrained LDA at least 45 days prior to the Base Residual Auction.

For LDAs in which the RPM Auctions for such Delivery Year result in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of a Participant-Funded ICTR into such LDA shall receive a payment equal to (i) average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased import capability, multiplied by (ii) MW amount of ICTRs allocated to holder. No payment will be issued to the holder when a zero or negative average weighted Locational Price Adder with respected to the immediate higher level LDA is calculated as a result of the RPM Auctions for such Delivery Year.

Participant-Funded ICTRs may be traded similar to CTRs.

6.1.3 Incremental Capacity Transfer Rights Associated with Incremental Rights-Eligible Required Transmission Enhancements

Incremental Rights-Eligible Required Transmission Enhancements may include Regional Facilities and Necessary Lower Voltage Facilities, and Lower Voltage Facilities. Regional Facilities are Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement (Rate Schedule FERC No. 42) that are included in Regional Transmission Expansion Plan (RTEP) and operate at or above 500 kV. Necessary Lower Voltage Facilities are Transmission Facilities that operate below 500 kV and must be constructed or strengthened to support new Regional Facilities. Lower Voltage Facilities are Transmission Facilities that operate below 500 kV which are included in RTEP to address one or more reliability violations or to address operational adequacy and performance issues and are not Necessary Lower Voltage Facilities. Responsible Customers, as defined in Schedule 12 of the Tariff, that are Network Customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners, and that are assigned cost responsibility for a Incremental Rights-Eligible Required Transmission Enhancement shall be allocated a share of the ICTRs associated with such facility in accordance with the percentage cost responsibility assigned to Responsible Customers for such facility as set forth in Schedule 12-Appendix to the Tariff.

ICTRs associated with Regional Facilities and Necessary Lower Voltage Facilities are determined and allocated to Responsible Customers. Effective with the 2013/2014 Delivery Year, ICTRs associated with Lower Voltage Facilities are also determined and allocated to Responsible Customers. The ICTRs (in MWs) associated with a given Incremental Rights-Eligible Required Transmission Enhancement are established by PJM prior to the conduct of the Base Residual Auction for the first Delivery Year for which such facility is to be in service. Once established, the ICTRs for such facility are available for allocation for 30 years or the life of the project, whichever is less.

PJM determines the increase in CETL into an applicable LDA as a result of a Incremental Rights-Eligible Transmission Enhancement planned for the Delivery Year. The increase in the CETL represents the ICTRs (in MWs) into the LDA provided by such planned facility. If such facility increases CETL into multiple LDAs, PJM will calculate 'simultaneous' increases in CETL into the LDAs and determine a separate ICTR MW amount for each LDA, equal to the respective increase in CETL into such LDA. .

The allocation (in MWs) of a Delivery Year's ICTRs for the Incremental Rights-Eligible Required Transmission Enhancement to a Responsible Customer may change during the Delivery Year if the percentage cost responsibility assigned to the Responsible Customers for such facility as set forth in Schedule 12-Appendix to the Tariff changes during the Delivery Year.

During the Delivery Year, each Network Customer (LSE) within a zone will be allocated a share of the zone's ICTRs associated with Incremental Rights-Eligible Required Transmission Enhancements for such Delivery Year in proportion to the customer's share of the zonal NSPL. These allocations may change day to day as end-use customers change from LSE to LSE.

ICTRs associated with Incremental Rights-Eligible Required Transmission Enhancements may be traded similar to CTRs.

The economic value of Incremental Rights-Eligible Required Transmission Enhancement ICTRs may change from year to year and will become zero when a zero or negative average weighted Locational Price Adder with respect to the immediate higher level LDA is calculated as a result of RPM Auctions for such Delivery Year.

The economic value (in $/day) of Incremental Rights-Eligible Required Transmission Enhancement ICTRs in an LDA as a result of all RPM Auctions for the Delivery Year is equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the MW quantity of Regional Project ICTRs in an LDA allocated to Responsible Customers.

6.2 Determination of Capacity Transfer Rights

For LDAs in which a positive average weighted Location Price Adder with respect to the immediate higher level LDA is calculated as a result of all RPM Auctions for the Delivery Year, the total amount of Capacity Transfer Rights in such LDA are equal to the Final Unforced Capacity Imported into such LDA as a result of all RPM Auctions for the Delivery Year. The Total CTRs into a constrained LDA are reduced by (1) an equivalent QTU import capability cleared, (2) Participant-Funded Project ICTRs, and (3) Incremental Rights-Eligible Required Transmission Enhancement ICTRs, and the remaining CTRs are allocated to the LSEs in the LDA (Zone). ICTRs may be reduced if the Total CTRs calculated for a constrained LDA are limited in any Delivery Year. If the total CTRs are limited, they will be reduced first to provide credits to a cleared QTU. The remaining CTRs will be allocated to Generation or Transmission Interconnection Customers and to Responsible Customers pro rata based on their original ICTR allocations.

$$LSECapacityTransferRights_{LDA} = FinalUnforcedCapacityImported_{LDA} - equivalentQTUcleared - ICTRs$$

Where:

The Final Unforced Capacity Imported into an LDA is equal to the Final Unforced Capacity Obligation for such LDA as a result of all RPM Auctions for such Delivery Year less the net participant buy bid/sell offers cleared in the LDA for all RPM Auctions for such Delivery Year.

- The Final LDA Unforced Capacity Obligation is equal to the sum of the Final Zonal Unforced Capacity Obligations for the zones in the LDA.

An equivalent QTU import capability cleared into an LDA is determined as the QTU BRA Auction Credits ($/day) received by the cleared QTU into an LDA divided by the weighted locational price adder of such LDA with respect to the immediate higher level LDA.

If the LDA into which the Incremental Capacity Transfer Rights are allocated or the import capability is increased by a Qualifying Transmission Upgrade is a part of a zone (e.g., DPL South or PS North), the calculations will be made based on the zone instead of the LDA using a Weighted Locational Price Adder for the zone with respect to the immediate higher level LDA to determine an equivalent Incremental Capacity Transfer Rights into the zone or an equivalent import capability into the zone in the case of a Qualifying Transmission Upgrade.

6.3 Allocation of Capacity Transfer Rights

The allocation of the total Capacity Transfer Rights in an LDA is performed on a pro-rata basis for each LSE based on the Daily Unforced Capacity Obligation that they serve in zones included in the constrained LDA. The allocated CTRs in an LDA will be reallocated to LSEs on a daily basis as load switches between retail suppliers within each zone.

When a Zone and its sub-zones are constrained LDAs, CTR calculations are performed on a Zonal basis.

When an LDA is entirely contained within another LDA (e.g., a Zone is a smaller LDA within a Group of Zones which is a larger LDA), a portion of the larger LDA Capacity Transfer Rights will be allocated to the smaller LDA, based on the smaller LDA's proportion of the larger LDA's unforced capacity obligation.

6.4 Capacity Transfer Rights Credits

LSEs that were allocated CTRs in a zone will receive a daily zonal CTR Credit as described in the Settlements section of this Manual.

Participants that were allocated Incremental CTRs into an LDA will receive a daily Incremental CTR Credit equal to the total Incremental CTRs allocated times the Final Incremental CTR Credit Rate for such LDA.

The Final Incremental CTR Credit Rate for an LDA is equal to the LDA's weighted Locational Price Adder with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year.

6.5 Capacity Transfer Rights Transfers

RPM Market Participants will have the ability to request CTR or ICTR Transfers by notifying PJM. The purpose of a CTR Transfer is to transfer the ownership of a specified amount of CTR MWs in a given zone from the Seller to the Buyer.

The following are business rules that apply to Capacity Transfer Rights Transfers:

- CTR Transfer requests must specify the buyer, seller, start and end dates of the transfer, the transfer amount (in MW), and the zone from which to transfer the CTRs.
- CTR Transfers will result in the "Buyer" receiving the credit that would have been due to the "Seller" of the CTRs.
- The smallest increment of CTRs that may be transferred is 0.1 MW.
- Both the Buyer and the Seller of a CTR Transfer Transaction must submit the CTR Transfer request to PJM before the following daily accounting deadlines (all times in Eastern Prevailing Time):
    - 1:00 PM (Tuesday – Friday) for transactions beginning on the previous day
    - 5:00 PM (Monday) for transactions beginning on Friday, Saturday, and Sunday
    - 5:00 PM (a day after the holiday) for transactions beginning on a holiday

Section 7: Load Obligations

Welcome to the *Load Obligations section* of the *PJM Manual for the PJM Capacity Market*. In this section, you will find the following information:

- An overview description of Load Obligations (see "Overview of Load Obligations")
- The business rules for determining Unforced Capacity Obligations (see "Unforced Capacity Obligations")
- The business rules for determining RPM Scaling Factors (see "RPM Scaling Factors")
- The business rules for determining Obligation Peak Load values (see "Obligation Peak Load")
- The process for determining load obligations (see "Process for Determining Load Obligations")
- The business rules for the treatment of Non-Zone Load (see "Non-Zone Load)

7.1 Overview of Load Obligations

In the Reliability Pricing Model, Unforced Capacity is the basis for the market product that is cleared in each auction. Unforced Capacity (UCAP) is installed capacity rated at summer conditions that is not, on average, experiencing a forced outage or forced de-rating. While unforced capacity (UCAP) is the basis for the valuation of generating capacity, in RPM, this concept is also used to value load management (Demand Resources (DR) and Interruptible Load for Reliability (ILR)), Energy Efficiency, Reliability Requirements of RTO and LDAs, and to define load obligations of Load Serving Entities. Load obligations are obligations to serve load or obligations to reduce load during the Delivery Year valued as unforced capacity.

Load Obligations are based on the Unforced Capacity Obligation procured in Base Residual Auction and all the Incremental Auctions.

7.2 Unforced Capacity Obligations

7.2.1 Determination of Unforced Capacity Obligations

Unforced Capacity Obligations are obligations for load to be served during the delivery year in unforced capacity terms. However, since RPM auction participants are not bidding in the demand for UCAP in the RPM process, the reliability requirement is forecasted on an aggregate basis prior to the clearing of the RPM Auctions as an input into the clearing process.

In the Reliability Pricing Model, unforced capacity obligations are determined for the RTO and Zones as a result of the Base Residual Auction and all Incremental Auctions.

The following parameters, discussed in detail below, are values used in the determination of Unforced Capacity Obligations:

- Peak Load Forecasts

- Forecast Pool Requirement (FPR)

7.2.2 Base Unforced Capacity Obligations

A Base RTO Unforced Capacity Obligation is determined after the clearing of the Base Residual Auction and is posted with the Base Residual Auction results. The Base RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the Base Residual Auction plus the RTO Short-Term Resource Procurement Target.

$$BaseRTOUnforcedCapacityObligation = UnforcedCapacityObligation_{inBRA} + Short-Term\,ResourceProcurementTarget$$

RTO Unforced Capacity Obligation satisfied in Base Residual Auction is used to determine the Base Zonal RPM Scaling Factors for use in determining Base Zonal Unforced Capacity Obligation.

Base Zonal Unforced Capacity Obligation

Zonal Unforced Capacity Obligations are determined based on an allocation of the RTO Unforced Capacity Obligation based on zonal peak load forecasts and zonal Short Term Resource Procurement Targets. As a result of the RPM Auction clearing process, additional resources above those required to meet the IRM may be procured and allocated to the zones. Since resource requirements in the constrained zones may be higher than those required based on IRM (FPR) these requirements affect the clearing price in the zones but not the allocation of RTO obligations to zones.

A Base Zonal Unforced Capacity Obligation is determined for each zone and is equal to the (Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement) + Zonal Short Term Resource Procurement Target.

$$BaseZonalCapObligation = (ZonalNormalizedSummerPeak - 4yr \times BaseZonalRPMScalingFactor \times FPR) + ZonalShort-Term\,ResourceProcurementTarget$$

Base Zonal Unforced Capacity Obligations are posted with the Base Residual Auction clearing results.

7.2.3 Final Zonal Unforced Capacity Obligations

The Final RTO Unforced Capacity Obligation is determined after the clearing of the final Incremental Auction for the Delivery Year. The Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year. The RTO unforced capacity obligation through all RPM Auctions is equal to the total MWs cleared in PJM Buy Bids in RPM Auctions less the total MWs cleared in PJM Sell Offers in RPM Auctions.

$$FinalRTOUnforcedCapObligation = SumofPJMBuyBidMWsCleared - SumofPJMSellOfersCleared$$

The Final Zonal Unforced Capacity Obligation is determined for each zone and is equal to zonal allocation of the Final RTO Unforced Capacity Obligation. The Final RTO Unforced

Capacity Obligation is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load Forecasts.

$$FinalZonalUnforcedCapOblig = (ZonalFinalPeakLoadForecast / RTOFinalPeakLoadForecast) * FinalRTOUCAPOblig$$

The Final Zonal Unforced Capacity Obligations are posted after the clearing of the final Incremental Auction for the Delivery Year.

7.3 RPM Zonal Scaling Factors

RPM Zonal Scaling Factors are calculated as a result of RPM Auctions and are constant for the Delivery Year. The following RPM Zonal Scaling Factors are determined:

- Base Zonal Scaling Factors – determined for each zone after the clearing of the Base Residual Auction
- Final Zonal Scaling Factors –determined for each zone two weeks after the final Incremental Auction.

These scaling factors account for (1) load growth from a prior-year summer to the Delivery Year; (2) any excess resources procured above those required to exactly meet the FPR requirements.

The following parameters are values used in the determination of RPM Zonal Scaling Factors:

- RTO Unforced Capacity Obligation (Base & Final)
- Zonal Peak Load Forecasts (Preliminary & Final)
- Forecast Pool Requirement (FPR)
- Zonal Weather Normalized Summer Peaks

The purpose of RPM Zonal Scaling Factors is to determine the LSE Daily UCAP Obligations in the zones from the Daily Obligation Peak Loads.

7.3.1 Zonal Weather Normalized Summer Peaks

To account for the load growth from a prior-year summer to each Delivery Year, PJM determines Zonal Weather Normalized Summer Peaks by October 31 prior to the start of the Delivery Year. The Zonal Weather Normalized Summer Peaks are calculated in accordance with the ***Load Data Systems Manual (M-19)***.

The RTO Weather Normalized Summer Peak is the sum of the Zonal Weather Normalized Coincident Summer Peaks.

The Electric Distribution Company (EDC) is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer prior to the Delivery Year and providing to PJM an Obligation Peak Load allocation for each eRPM defined "area" within their zone by December 31 prior to the start of the Delivery Year. *See Reliability Assurance Agreement Schedule 8, Section A* for the limitations in the netting of Non-Retail Behind the Meter Generation.

7.3.2 Base Zonal RPM Scaling Factor

A Base Zonal RPM Scaling Factor is determined for each zone and is equal to the [(Preliminary Zonal Peak Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year[10])* ((RTO Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement))]. Zonal peak load is adjusted for peak loads of zone/areas that elected FRR option.

$$BaseZonalRPMScalingFactor = [(\frac{PrelimZonalPeakLoadForecast)^5}{NormalizedSummerPeak - 4yr})\times(\frac{RTOUnforcedCapacityObligation_{inBRA}}{RTOPreliminaryPeakLoadForecasts \times FPR})$$

Base Zonal RPM Scaling Factors are posted with the Base Residual Auction results.

7.3.3 Final Zonal RPM Scaling Factor

The Final Zonal RPM Scaling Factors are used in determining an LSE's Daily Unforced Capacity Obligation. A Final Zonal RPM Scaling Factor for a zone is equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Peak for the summer prior to the Delivery Year).

$$FinalZonalRPMScalingFactor = \frac{FinalZonalUnforcedCapacityObligation}{FPR \times ZonalWeatherNormalizedPeak - 1yr}$$

7.4 Obligation Peak Load

Obligation Peak Load is the peak load value on which LSEs' Unforced Capacity Obligations are based. Each PJM Electric Distribution Company (EDC) is responsible for allocating its normalized previous summer's peak to each customer in the zone (both retail and wholesale). The process used by the EDC to determine these Peak Load Contributions is based on rules negotiated with its regulators. LSE Obligation Peak Load represents the summation of Peak Load Contributions for each of an LSE's customers.

- The Obligation Peak Load allocation for a zone is constant and effective for the entire Delivery Year.
- The EDC is also responsible for allocating the Obligation Peak Load for a zone/area among end-use customers by calculating Peak Load Contributions (i.e., "capacity tickets") for each end-use customer by December 31 prior to the start of the Delivery Year.
- The EDC must make Peak Load Contribution information available to LSEs by December 31 prior to the start of the Delivery Year.

[10] For the 2007/2008-2010/2011 Delivery Years, the Zonal Weather Normalized Summer Peak for the summer 2006 will be used to establish Base Zonal RPM Scaling Factors.

7.5 Daily Unforced Capacity Obligations

The EDC is responsible for uploading Obligation Peak Load data into eRPM for every LSE serving load in their zone/area during the Delivery Year. The file upload must be performed in accordance with eRPM's file format specifications and by the file upload deadline (36 hours before the start of the operating day).

- The daily sum of all the LSEs' Obligation Peak Load data in a zone/area must equal the EDC's Obligation Peak Load allocation to the zone/area.
- A Daily Obligation Peak Load Scaling Factor will be used to scale the uploaded LSE Obligation Peak Load values to the fixed Obligation Peak Load Allocation of the zone/area in the event that the Obligation Peak Load values uploaded by the EDC do not exactly sum to the Annual Obligation Peak Load Allocation for the zone/area.

$$\text{DailyOblPkLoadScalingFactor} = \frac{\text{Annual Zone Area Obligation Peak Load Allocation}}{\sum \text{Zone Area Obligation Peak Load Uploads}}$$

- The daily sum of the Obligation Peak Load data for all areas in a zone must equal the Zonal Weather Normalized Summer Peak for the summer prior to the Delivery Year.
- The Daily Unforced Capacity Obligation of an LSE in a zone/area equals the LSE's Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement.

$$DailyUnforcedCapObligation = ObligationPeakLoad \times FinalZonalRPMScalingFactor \times FPR$$

- During the Delivery Year, the Daily Unforced Capacity Obligation of an LSE is locked 36 hours before the start of the operating day.

7.6 Process for Determining Load Obligations

The process that was described in the previous sections is illustrated below.

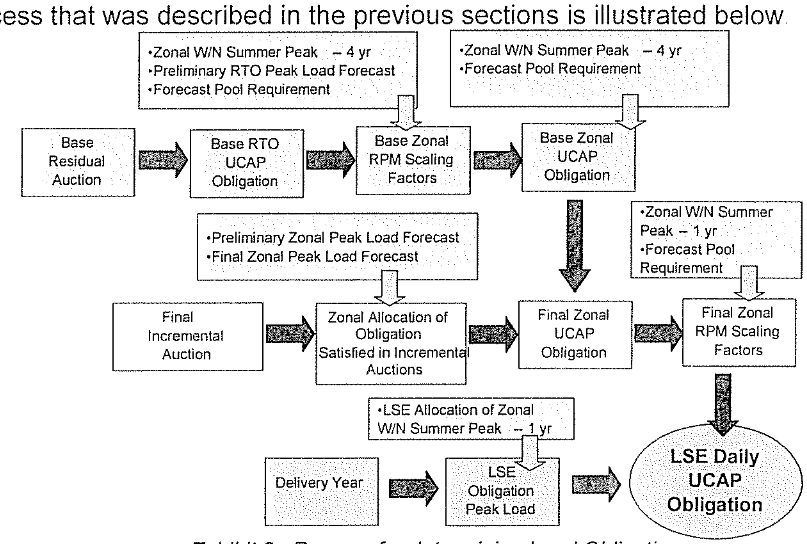

Exhibit 3: Process for determining Load Obligations

7.7 Treatment of Non-Zone Load

Non-Zone Load is the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

The following are business rules that apply to Treatment of Non-Zone Load:

- Non-Zone Load may be Non-Zone Network Load (Tariff 1.27B) that is charged a Network Integration Transmission Service (NITS) charge (Tariff Attachment H-A) or other load that may be 'grandfathered' from the NITS charge.
- PJM forecasts the Preliminary Non-Zone Load for the RPM Delivery Year and includes it in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load of the Zone from which the Non-Zone Load is served, by February 1 prior to the Base Residual Auction.
- Non-Zone Load cannot be served in a Delivery Year using resources committed to RPM if it is not included in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load prior to the RPM Base Residual Auction for the Delivery Year.
- PJM forecasts the final Non-Zone Load for the RPM Delivery Year and includes it in the Final RTO Forecast Peak Load and the Final Zonal Forecast Peak Load that is posted by January prior to the Final Incremental Auction.
- EDC that is responsible to determine the Obligation Peak Loads for the Zone will also establish the Obligation Peak Load associated with the Non-Zone Load by December 31 prior to the start of the Delivery Year.
- Non-Zone load will be modeled as a defined "area" in the zone from which it is served in the eRPM system.

The LSE serving the Non-Zone Load will be assessed a Daily Unforced Capacity Obligation and will be responsible to pay an RPM Locational Reliability Charge.

Section 8: Resource Performance Assessments

Welcome to the *Resource Performance Assessments* section of the PJM Manual for the *PJM Capacity Market*. In this section, you will find the following information:

- An overview description of the resource performance assessments (see "Overview of Resource Performance Assessments")
- The business rules for determining RPM commitment compliance (see "RPM Commitment Compliance")
- The business rules for determining generating unit peak-hour availability (see "Generating Unit Peak-Hour Availability")
- The business rules for determining load management event compliance (see "Load Management Event Compliance")
- The business rules for determining load management test compliance (see "Load Management Test Compliance"
- The business rules for replacement resources ("see "Replacement Resources")

8.1 Overview of Resource Performance Assessments

The PJM Capacity Market is designed to ensure that capacity market prices are consistent with system reliability metrics. All LSEs must satisfy their capacity obligation either through the RPM or through the FRR Alternative. If a resource receives capacity payments, or in the case of FRR Alternative, is committed to directly satisfy load obligation requirements, there is an expectation that the resource will honor their commitments and provide reliability services when required. The following performance assessments provide the means to assess whether or not a resource honored their commitments and provided the expected reliability services during the Delivery Year.

- RPM Commitment Compliance
- Generating Unit Peak-Hour Period Availability
- Summer/Winter Capability Testing
- Peak Season Maintenance (PSM) Compliance
- Load Management Compliance
- Load Management Test Compliance
- Measurement & Verification (M &V) Audit (see Manual 18-B)

Collectively, the performance assessments provide consumers, who have paid for a high level of reliability through their capacity market payments, with reasonable assurance that the resources committed to RPM or FRR Alternative will perform at adequate levels during the Delivery Year. Since failure to perform in a performance assessment results in deficiency or penalty charges, resource providers are incented to ensure that their committed resources perform during the Delivery Year in order to limit their exposure to deficiency or penalty charges.

A resource will have an RPM Resource Commitment if the resource cleared or received make-whole payments through an RPM Auction or if the unit was specified as a replacement resource. A resource will have an FRR Capacity Plan commitment if the unit was included in an FRR Capacity Plan. Portions of the resource that do not have an RPM Resource Commitment or FRR Capacity Plan Commitment during the Delivery Year are not subject to resource performance assessments and the associated deficiency/penalty charges.

The performance assessments are not applicable to all types of resources committed to RPM or FRR Alternative. The following matrix provides an overview of the applicability of resource performance assessments.

Assessment	Generation (except Hydro, Wind & Solar)	Hydro	Wind & Solar Generation	DR	EE	QTU
RPM Commitment Compliance	X	X	X	X	X	X
Peak-Hour Period Availability	X	X				
Summer/Winter Capability Testing	X	X (Annual)				
PSM Compliance	X					
Load Management Event Compliance				X		
Load Management Test Compliance				X		
M&V Audit					X	

8.2 RPM Commitment Compliance

A resource committed to RPM is expected to be able to deliver unforced capacity during the Delivery Year that is equal to or greater than the unforced capacity committed through RPM Auctions or through the specification of replacement capacity. RPM Commitment Compliance is evaluated daily during the Delivery year on a resource-specific basis to determine if a party satisfied their Daily RPM Resource Commitments on their generation resources, demand resources, and Qualifying Transmission Upgrades (QTUs).

A resource or portion of a resource committed to the FRR Alternative is not subject to RPM Commitment Compliance. Instead of unit-specific commitment compliance, FRR Entities are subject to daily unforced capacity obligation compliance.

8.2.1 Generation

A generation resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Unit cancellations and delays – A planned generation is cancelled or delayed and does not commence Interconnection Service prior to the start of the Delivery Year.
- Unit deratings and retirements – The generation resource is derated (through a Capacity Modification decrease) prior to or during the Delivery year. (Retirements result in derating the installed capacity value of a unit to zero MWs through a Capacity Modification decrease in the eRPM system).
- EFORd increases – The final Effective EFORd for a generation resource during the Delivery Year is greater than the Sell Offer EFORds submitted in cleared offers in RPM Auctions for the Delivery Year.

During the Delivery Year, failure to meet generation resource commitments will be determined by comparing a party's Daily RPM Generation Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Generation Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM Generation Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(1-Effective EFORd).

$$DailyRPMResourcePostion_{GenResource} = (DailyICAPOwned - DailyFRRCapPlanCommitments - Daily\ Unoffered\ ICAP) \times (1 - EffectiveEFORd)$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such unit in RPM Auctions to decreases/increases of RPM Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity and the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a specific unit is calculated as Daily RPM Resource Commitments minus Daily RPM Generation Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{GenResource} = DailyRPMResourceCommitments - DailyRPMGenerationResourcePosition$$

8.2.2 Demand Resources:

A demand resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Load management program cancellation or delay– The load management program(s) associated with the planned demand resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.
- Decrease in nominated value of demand resource – The final nominated value of the demand resource during the Delivery Year is less than the nominated value of the

demand resource used in cleared offers in RPM Auctions for the Delivery Year due to a decrease in the peak load contributions (i.e., capacity tickets) of end-use customers providing the actual load response.

- Failure to have enough sites registered and approved in the eLRS system prior to the start of the Delivery Year to support the nominated value of the demand resource committed for such Delivery Year. Effective with the 2014/2015 DY, the sites registered and approved in the eLRS must be the same resource product type (limited, extended summer, or annual) as the demand resource committed.
- Decrease in the DR Factor or Forecast Pool Requirement - The final UCAP value of the demand resource during the Delivery Year is less than the UCAP value committed in the auction due to the final DR Factor or final FPR for the Delivery Year being less than the DR Factor or FPR that was used in RPM Auction for which the demand resource cleared.

During the Delivery Year, failure to meet demand resource commitments will be determined by comparing a party's Daily RPM Demand Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Demand Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily Nominated DR Value – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP) * DR Factor * Forecast Pool Requirement.

$$DailyRPMPosition_{DR} = (DailyNominatedDRValue - DailyFRRCapacityPlanCommitments - DailyUnofferedICAP) \times DRFactor \times FPR$$

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such demand resource in RPM Auctions to decreases/increase of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a specific demand resource is calculated as Daily RPM Resource Commitments minus Daily RPM Demand Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{DR} = DailyRPMResourceCommitments - DailyRPMDemandResourcePosition$$

Existing demand resources that offered and cleared in Base Residual Auction, First Incremental Auction, or Second Incremental Auction can receive relief from deficiency charges if they failed to meet their RPM Resource Commitments due to a decrease in Peak Load Contributions (i.e., "capacity ticket(s)") that were due to the permanent departure of load from the transmission system (e.g., plant closure, efficiency gains, or similar reasons) that was relied upon for load response. The resource provider of the existing Demand Resource must provide PJM with all information deemed necessary by PJM to assess the merits of the request for relief.

Request for relief from deficiency charges must be made no later than two weeks in advance of the opening of the of the Third Incremental Auction. Failure to maintain Demand Resources will not permit relief. If relief from deficiency charges is granted, the resource provider will receive a reduction in their RPM Auction Credits and a reduction in their RPM Resource Commitments. Any reduction in Auction Credits is factored into the calculation of the Final Zonal Capacity Price. There is no relief from deficiency charges for existing Demand Resources that offered and cleared in a Third Incremental Auction.

8.2.3 Energy Efficiency Resources:

An EE resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Energy efficiency installation cancellation or delay– The energy efficiency installation(s) associated with the planned EE Resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.
- Decrease in nominated value of EE Resource – The final nominated value of the energy efficiency resource during the Delivery Year is less than the nominated value of the energy efficiency resource used in cleared offers in RPM Auctions for the Delivery Year due to a change in number of planned installations associated with the planned EE Resource, change in EDC loss factor, or change due to post-installation measurement and verification activities, or reduction in nominated value due to failure to meet the precision standard requirement for measurement and verification activities in accordance with the PJM Manual for Energy Efficiency Measurement & Verification.

During the Delivery Year, failure to meet EE Resource commitments will be determined by comparing a party's Daily RPM EE Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM EE Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM EE Resource Position for a specific EE resource is equal to the (Daily Nominated EE Value – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP) * DR Factor * Forecast Pool Requirement).

$$DailyRPMPosition_{EE} = (DailyNominatedEEValue - DailyFRRCapacityPlanCommitments - DailyUnofferedICAP) \times DRFactor \times FPR$$

A party's Daily RPM Resource Commitments for a specific EE resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such EE resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a specific EE resource is calculated as Daily RPM Resource Commitments minus Daily RPM EE Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{EE} = DailyRPMResourceCommitments - DailyRPMEEResourcePosition$$

8.2.4 Qualifying Transmission Upgrade (QTU):

A provider of a Qualifying Transmission Upgrade may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Upgrade cancellations and delays– A qualifying transmission upgrade is cancelled or delayed and does not commence Interconnection Service prior to the start of the Delivery Year.

During the Delivery Year, failure to meet qualifying transmission upgrade commitments will be determined by comparing a party's Daily RPM QTU Position to their Daily RPM Resource Commitments for such upgrade. If a party's Daily RPM QTU Position is less than their Daily RPM Resource Commitments for such upgrade on a delivery day, a Transmission Upgrade Delay Penalty will be assessed on the RPM Commitment Shortage.

A party's Daily RPM QTU Position for a Qualifying Transmission Upgrade is equal to the approved incremental import capability value into the Sink LDA from a Source LDA for such upgrade.

A party's Daily RPM Resource Commitments for a specific Qualifying Transmission Upgrade are calculated by adding the sum of any UCAP Cleared plus UCAP Make whole for such qualifying transmission upgrade in RPM Auctions to decreases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a Qualifying Transmission Upgrade is calculated as Daily RPM Resource Commitments minus Daily RPM QTU Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{QTU} = DailyRPMResourceCommitments - DailyRPMQTUPosition$$

8.3 Commitment Level Used in Peak-Hour Period Availability (PHPA), Summer/Winter Capability Tests, and PSM Compliance

Since the RPM Resource Commitments or FRR Capacity Plan Commitments on a unit can vary daily during the delivery year, a Total Unit ICAP Commitment Amount is calculated for each unit and used as the basis for assessing the performance of a unit for peak-hour period availability, summer/winter capability tests, and PSM compliance.

Since replacement resources can be specified anytime during the Delivery Year, the Total Unit ICAP Commitment Amount is not finalized until after the conclusion of the Delivery Year.

The Total Unit ICAP Commitment Amount on a specific unit is equal to the lesser of (a) the Unit Average Daily ICAP Commitment Amount for the Delivery Year or (b) maximum Summer Net Dependable Rating of the Unit during the Delivery Year.

$$TotalUnitICAPCommitment = \text{Lessof}(UnitAvgDailyICAPCommitment, \text{Max}(SummerNetDependableRating))$$

The Unit Average Daily ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the (sum of all Daily RPM Resource Commitments on such unit for the Delivery Year divided by one minus the Effective EFORd plus the sum of all Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 days (or 366 days).

$$UnitAvgDailyICAPCommitment_{Unit} = \frac{\left(\sum DailyRPMResourceCommitments_{Unit}/(1 - EffectiveEFORd_{Unit})\right) + \sum DailyFRRCapPlanCommitments_{Unit}}{365\ days\ (or\ 366\ days)}$$

Since a single unit can have both RPM Commitments and FRR Capacity Plan Commitments during the Delivery Year, a Unit Average Daily FRR ICAP Commitment Amount and Unit Average Daily RPM ICAP Commitment Amount for the Delivery Year is calculated for each unit.

The Unit Average Daily FRR ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of all Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 days (or 366 days).

$$UnitAverageDailyFRR\,ICAPCommitmentAmount = \frac{DailyFRRCapacityPlanCommitments_{for\,DY}}{365days(or366days)}$$

The Unit Average Daily RPM ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the Total Unit ICAP Commitment Amount less the Unit Average Daily FRR ICAP Commitment Amount.

$$UnitAverageDailyRPM\,ICAPCommitment_{GenResource} = TotalUnitICAPCommitment - UnitAverageDailyFRR\,ICAPCommitement$$

Since a single unit can be committed by multiple parties, a Provider's Average Daily FRR ICAP Commitment Amount, Provider's Average Daily RPM ICAP Commitment Amount, and Provider's Share of Total Unit ICAP Commitment Amount for each unit is calculated in order for PJM to allocate any unit shortfalls calculated for peak-hour period availability, summer/winter capability testing, and PSM compliance.

A Provider's Average Daily FRR ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of the Provider's Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 (or 366 days).

$$Provider'sAverageDailyFRRICAPCommitmentAmount_{for\ Gen\ Resource} = \frac{Provider'sDailyFRRCapacityPlanCommitments_{for\ Gen\ Resource\ for\ DY}}{365days(or366days)}$$

A Provider's Average Daily RPM ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of the Provider's Daily RPM Resource Commitments on such unit the Delivery Year divided by the sum of all Daily RPM Resource Commitments on such unit for the Delivery Year, multiplied by the Unit Average Daily RPM ICAP Commitment Amount.

$$Provider's\ AvgDailyRPMICAPCommitment = (\sum Provider's\ Daily\ RPMCommitments / \sum Total\ Daily\ RPMResourceCommitments) * Unit\ Avg\ DailyICAPcommitment$$

A Provider's Share of the Total Unit ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the Provider's Average Daily FRR ICAP Commitment Amount plus the Provider's Average Daily RPM ICAP Commitment Amount.

$$Provider'sShareofTotalUnitICAPCommitment_{GenResource} = Provider'sAverageDailyFRRICAPCommitment + Provider'sAvgDailyRPMICAPCommitment$$

8.4 Generating Unit Peak-Hour Period Availability

The Generating Unit Peak-Hour Period Availability (PHPA) metric provides a means to assess whether committed generation resources are available at expected levels during critical peak periods, and credits or charges resource providers to the extent that they exceed or fall short of that expected availability. The metric provides generation owners an added incentive to ensure that their capacity resources are available when they are most needed, and provide loads greater assurance that their payments for capacity will help maintain peak-hour period reliability.

The Generating Unit-Peak-Hour Period Availability metric is applicable to all capacity resources committed to serve load either under Reliability Pricing Model or Fixed Resource Requirement Alternative. It is not applicable to wind and solar generation.

PJM will directly measure generation availability performance during peak load periods. The peak hour periods are defined based on the summer and winter operating periods when high demand conditions are likely to occur and therefore generation performance is most critical to maintaining system reliability. The peak hour periods include: The hour ending 15:00 local prevailing time (LPT) through the hour ending 19:00 LPT on any day during the calendar months of June through August that is not a Saturday, Sunday, or a federal holiday, and the hour ending 8:00 LPT through the hour ending 9:00 LPT and the hour ending 19:00 LPT through the hour ending 20:00 LPT on any day during the calendar months of January and February that is not a Saturday, Sunday, or a federal holiday. The total number of hours is approximately 500, and can vary from year to year.

Generating Unit Peak-Hour Period Availability is measured by calculating a Peak-Period Equivalent Forced Outage Rate (EFORp) and the corresponding Peak Period Capacity Available (PCAP) for a generation resource. The PCAP of a unit is compared to a unit's Target Unforced Capacity (TCAP), which is based on a unit's Equivalent Demand Forced Outage Rate-5 (EFORd-5), to assess whether or not a unit fell short of or exceeded its expected availability during the defined peak-hour periods.

8.4.1 Peak-Period Equivalent Forced Outage Rate (EFORp)

Peak-Period Equivalent Forced Outage Rate Peak (EFORp) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate during the defined peak hour periods. The EFORp is based on actual outage data during the Delivery Year.

The Peak-Period Equivalent Forced Outage Rate (EFORp) is determined by using the following sets of hours from the defined peak hour periods:

- Forced outage hours when needed (outage hours exclude Outside Management Control (OMC) events),
- Forced partial outage hours when needed (outage hours exclude OMC events), and
- Service hours.

The ***"outage hours when needed"*** shall be determined by PJM by identifying hours during which the real-time LMP would have exceeded the cost-based offer for the unit or when PJM would have (absent the outage) called the unit for operating reserves, taking into account the unit's operating constraints.

EFORp is the sum of forced outage hours when needed plus equivalent forced partial outage hours when needed, divided by service hours plus forced outage hours when needed.

$$EFORp = \frac{(ForcedOutageWhenNeeded + EquivalentForcedPartialOutageHoursWhenNeeded)}{(ServiceHours + ForcedOutageHoursWhenNeeded)}$$

If the service hours of a unit are less than 50 hours during the defined peak hour periods, the EFORp will be the lesser of the EFORd calculated based on outage data that covers the entire Delivery Year or the calculated EFORp based on peak hour period outage data.

In the calculation of the EFORp for a specific unit the following considerations are made:

- If a summer/winter capability test resulted in a partial forced outage that was entered by PJM in eGADs, the partial forced outage will not be considered in the calculation of the unit's EFORp.
- During the time period that a unit is delayed or retired, forced outages are not reported on the unit. As a result, performance of the unit during the time it is delayed or retired is not considered in the calculation of the unit's EFORp.
- For a single-fueled, natural gas-fired unit, forced outages during the winter peak-hour period will not be used in determining the unit's EFORp (or EFORd for generation units with service hours below 50 hours) if the resource provider can demonstrate that such failure was due to non-availability of gas to supply the unit as a result of events that were Outside of Management Control (OMC). The PJM eGADs Manual provides guidelines for the application of OMC codes. Lack of fuel in the cases where the operator of the unit is not in control of contracts, supply lines, or delivery of fuels is considered an OMC event. Whereas, lack of fuel in the case where an operator elected to contract for fuels where the fuel can be interrupted as part of a fuel cost-saving measure is under management control and is not considered an OMC event.

An estimate of each unit's EFORp will be posted to the eRPM system within three calendar months after the end of the summer period.

8.4.2 Peak Period Capacity Available (PCAP)

The Peak Period Capacity Available (PCAP) for a unit represents the actual availability of the committed portion of the unit during the defined peak-hour periods. PCAP is calculated by multiplying the unit's Total Unit ICAP Commitment Amount times one minus the unit's EFORp.

$$PCAP = TotalUnitICAPCommitment \times (1.0 - EFORp)$$

8.4.3 Equivalent Demand Forced Outage Rate (EFORd-5)

Equivalent Demand Forced Outage Rate (EFORd-5) is an EFORd based on 5 years of outage history that provides the basis for a unit's expected availability during the peak-hour periods.

EFORd-5 is an index that is calculated in a manner similar to the EFORd that is the basis for a unit's UCAP value for the Delivery Year, except the EFORd-5 is determined using five years instead of one year of outage data. The index is calculated using five years of Generator Availability Data System (GADS) outage data excluding OMC events through September 30 prior to the Delivery Year. If a generating unit does not have a full five years of history, the EFORd-5 will be calculated using the class average EFORd and the available history as described in Reliability Assurance Agreement, Schedule 5, Section C. For a new generating unit, the class average EFORd will be used as the EFORd-5. The class average

EFORds that are used by PJM to calculate a unit's EFORd-5 are posted to the PJM website by November 30 prior to the Delivery Year.

PJM will post the ***EFORd-5*** that is effective for the Delivery Year to the eRPM system by November 30 prior to the Delivery Year.

8.4.4 Target Unforced Capacity (TCAP)

The Target Unforced Capacity (TCAP) for a unit represents the expected availability of the committed portion of the unit during the defined peak-hour periods. TCAP is calculated as the Total Unit ICAP Commitment Amount times one minus the unit's EFORd-5

$$TCAP = TotalUnitICAPCommitment \times (1.0 - EFORd - 5)$$

8.4.5 Peak-Hour Period Capacity Shortfall

The PCAP value of a unit is compared with the TCAP value of a unit to determine if a unit fell short of or exceeded its expected availability during the defined peak-hour periods. The Unit Peak-Hour Period Capacity Shortfall is equal to the TCAP minus the PCAP for such unit.

$$UnitPeakHourPeriodCapShortfall = TCAP - PCAP$$

A positive Unit Peak-Hour Period Capacity Shortfall indicates a shortfall in meeting a unit's expected availability (underperformance) and a negative Unit Peak-Hour Period Capacity Shortfall indicates that the unit exceeded its expected availability (over performance).

There are limitations on the amount of positive Unit Peak-Hour Period Capacity Shortfall that may be calculated for a specific unit. The limitations include the following:

- A Unit Peak-Hour Period Capacity Shortfall is limited, on a unit specific basis, to 50% of the Total Unit ICAP Commitment Amount * (1-Effective EFORd).
- If the 50% limitation is triggered in a Delivery Year, the limit will increase to 75% in the following Delivery Year.
- If the 75% limitation is triggered in a Delivery Year, the limit will increase to 100% in the following Delivery Year.
- The 50% limit will be reinstated after 3 years of good performance.

If portions of the unit were committed by multiple Resource Providers, the Unit Peak-Hour Period Capacity Shortfall for the unit is allocated to Resource Providers based on the provider's pro-rata share of the Total Unit ICAP Commitment Amount.

For a Resource Provider, the net of their Unit Peak-Hour Period Capacity Shortfalls in an LDA across committed units in an LDA are determined.

The netting of Unit Peak-Hour Period Capacity Shortfalls in an LDA is performed across committed units within a single account in eRPM. There is no netting of shortfalls performed across multiple accounts in eRPM.

The net Peak-Hour Period Capacity Shortfall in an LDA may be adjusted by a Provider's Net Eligible Available PHPA Shortfall in an LDA (i.e., Provider's Net PHPA Replacement Capacity in a LDA) as explained in Section 8.4.5.1.

A Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA will be separated into an Adjusted Net Peak Hour Period Capacity Shortfall in an LDA for RPM Resource Commitments and an Adjusted Net Peak Hour Period Capacity Shortfall in an LDA for FRR Capacity Plan Commitments as explained in Section 8.4.5.1.

Preliminary EFORp estimates (based on summer peak hours) for committed units and estimates of a Resource Provider's Net Peak-Hour Period Capacity Shortfall for RPM Resource Commitments in an LDA and Net Peak-Hour Period Capacity Shortfall for FRR Resource Commitments in an LDA will also be provided through the eRPM System in November of the Delivery Year. Such estimates do not consider any adjustment for a Provider's Net Eligible Available PHPA Shortfall in an LDA.

The Adjusted Net Peak-Hour Period Capacity Shortfall in an LDA is applied to each day in the Delivery Year. A Resource Provider with a positive Adjusted Net Peak-Hour Period Capacity Shortfall in an LDA will be assessed a Peak-Hour Period Availability Charge retroactively for each day in the Delivery Year.

8.4.5.1 Use of Excess Available Capacity in Peak-Hour Period Availability Assessment

Excess available capacity (i.e. uncommitted capacity) in a party's portfolio that satisfies the capacity resource obligations of a committed resource may be used to help cure or offset a party's shortfall for peak hour period availability.

Calculation of Eligible Available Capacity (EAC) for Individual Units

PJM will determine the Eligible Available Capacity (EAC) for each generation resource. A unit's EAC represents the amount of the unit's available capacity for the DY that met the capacity resource obligations by (1) offering into the DA Energy Market (if available) (2) satisfying summer and winter capability test requirements (i.e., test to their committed ICAP level) and (3) entering outages into eDart and GADS.

PJM will determine the Daily EAC for a unit for each day of the Delivery Year and calculate the resource's Average Daily EAC for the entire Delivery Year.

- For a unit that (1) passed Summer and Winter Capability Tests; or (2) failed their Summer or Winter Capability Test, but for which the owner/operator entered a partial forced outage in the eGADS system for the difference between the claimed summer or winter ICAP rating and the test result. (Essentially these are units that will not be assessed Rating Test Failure Charges.)

  Daily EAC = Lesser of (Daily Minimum Hourly ECOMAX in DA Energy Market, Daily Summer Net Dependable Rating of Unit) – Lesser of (Daily ICAP Commitment MWs, Daily Summer Net Dependable Rating) – Daily Unoffered ICAP MWs

  Where:

  Daily Minimum Hourly ECOMAX in the DA Energy Market is determined from the price based offer submitted in eMarkets. If no price offer is available then the schedule of the cheapest cost schedule will be used. Hourly ECOMAX values can be viewed on the Unit Schedule Hourly tab in eMarkets.

  Daily Summer Net Dependable Rating is the daily summer ICAP rating of the unit that is based on approved Capacity Modifications for the unit in the eRPM system.

Daily ICAP Commitment MWs = Sum of unit's Daily RPM Commitments in UCAP/(1 – Final EFORd for DY) + Sum of unit's Daily FRR Capacity Plan Commitments in ICAP]

Daily Unoffered ICAP MWs represents the total amount of ICAP MWs that were not offered from the unit by RPM entities in RPM Auctions for the Delivery Year. Daily Unoffered ICAP MWs does not include the Unoffered MWs of an FRR Entity.

- For a unit that failed their Summer or Winter Capability Test and the owner/operator failed to enter a partial forced outage in the eGADS system for the difference between their claimed summer or winter ICAP rating and their test result (Essentially these are units that have the potential to be assessed Rating Test Failure Charges):

  Daily EAC = Lesser of (Daily Minimum Hourly ECOMAX in DA Energy Market, Daily Summer Net Dependable Rating of Unit, Test Result) – Lesser of (Daily ICAP Commitment MWs, Daily Summer Net Dependable Rating) – Daily Unoffered ICAP MWs

  Where:

  Daily Minimum Hourly ECOMAX, Daily Summer Net Dependable Rating of Unit, Daily ICAP commitment MWs and Daily Unoffered ICAP MWs are defined above.

  For June 1 – Oct 31, the Test Result will be the unit's Summer Test Result. From November 1 – May 31, the Test Result will be the unit's Winter Test Result. For Hydro Units, the Test Result will be the hydro unit's annual test result.

- If a negative Daily EAC is calculated, a zero Daily EAC will be used in the calculation of the Average Daily EAC.

- A unit's Average Daily EAC for the delivery year is equal to the [Sum of the Daily EAC for the Delivery Year]/Number of Days in the Delivery Year.

<u>Allocation of a Unit's Average Daily EAC to Multiple Providers</u>

If portions of the unit are committed by multiple resource providers, the unit's Average Daily EAC is allocated to resource provider's that had available capacity during the Delivery Year to determine a Provider's Share of Average Daily EAC. The pro-rata allocation will be based on the provider's Average Daily Available ICAP MWs on such unit for the entire Delivery Year.

- The Provider's Daily Available ICAP on a unit is captured from the eRPM system and is based on the provider's Daily ICAP Owned, Daily Unoffered ICAP, Daily RPM Resource Commitments, and Daily FRR Capacity Plan Commitments. If a negative Daily Available ICAP value is calculated, a zero Daily Available ICAP will be used in the calculation of the Provider's Average Daily Available ICAP for the Delivery Year.

- For a provider, Daily Available ICAP = Daily ICAP Owned – Daily Unoffered ICAP – (Daily RPM Resource Commitments/(1 – Final DY EFORd) – Daily FRR Capacity Plan Commitments

  Where:

  Daily Unoffered ICAP MWs does not include the Unoffered MWs of an FRR Entity.

- A provider's Average Daily Available ICAP for the Delivery Year is equal to the [Sum of the provider's Daily Available ICAP for the Delivery Year]/Number of Days in the Delivery Year.

Calculation of a Provider's Net Eligible Available PHPA Shortfall in LDA (i.e., Provider's Net PHPA Replacement Capacity in LDA)

PJM will calculate the Provider's share of Peak Period Capacity Available (PCAP) for the eligible available capacity portion of such unit (i.e., share of Eligible Available PCAP) as Provider's Share of Average Daily EAC *(1 – EFORp).

For each provider, PJM will determine a Provider's Net Eligible Available PHPA Shortfall in an LDA (which represents the Provider's Net PHPA Replacement Capacity in an LDA) by summing the Provider's share of Eligible Available PCAP values for all units in an LDA within a provider's RPM account. Netting is performed across a single eRPM account only. PJM will not net values across a provider's multiple eRPM accounts. The Eligible Available PHPA Shortfall (or Resource Provider's Net PHPA Replacement Capacity in an LDA) will be represented as a negative value in the eRPM system indicating excess or over performance.

A Provider's Net Eligible Available PHPA Shortfall in an LDA (i.e., Provider's Net PHPA Replacement Capacity in a LDA) is used to reduce a party' positive Net Peak Hour Period Capacity Shortfall in an LDA in their single RPM account. A Provider's Net Eligible Available PHPA Shortfall in an LDA may not be used to reduce a party's negative Net Peak Hour Period Capacity Shortfall in an LDA. Please see Manual 18, Section 8 for details on how a party's Net Peak Hour Period Capacity Shortfall in an LDA is calculated.

Calculation of a Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA

When a Provider's Net Peak Hour Period Capacity Shortfall in an LDA is a positive value, a Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA is equal to the provider's Net Peak Hour Period Capacity Shortfall in the LDA minus the provider's absolute value of Net Eligible Available PHPA Shortfall in an LDA; however, if the calculated value is negative, the Adjusted Net Peak Hour Period Capacity Shortfall in an LDA will be set to zero. When a Provider's Net Peak Hour Period Capacity Shortfall in an LDA is zero or negative, the Adjusted Net Peak Hour Period Capacity is equal to the Provider's Net Peak Hour Period Capacity Shortfall in an LDA.

Allocation of a Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA between RPM and FRR Commitments

A Provider's Adjusted Net Peak Hour Period Capacity Shortfall in an LDA will be separated into an Adjusted Net Peak Hour Period Capacity Shortfall in an LDA for RPM Resource Commitments and an Adjusted Net Peak Hour Period Capacity Shortfall in an LDA for FRR Capacity Plan Commitments.

- A Provider's Adjusted Net Peak Hour Period Capacity Shortfall in LDA for RPM Resource Commitments = provider's Adjusted Net Peak Hour Period Capacity Shortfall in LDA*provider's Net Average Daily RPM ICAP Commitment Amount in LDA/provider's Net Share of Total Unit ICAP Commitment Amount in LDA.

- A Provider's Adjusted Net Peak Hour Period Capacity Shortfall in LDA for FRR Commitments = provider's Adjusted Net Peak Hour Period Capacity Shortfall in

LDA*provider's Net Average Daily FRR ICAP Commitment Amount in LDA/provider's Net Share of Total Unit ICAP Commitment Amount in LDA.

8.4.6 Summer/Winter Capability Testing

During the Delivery Year, generation owners are responsible to perform Summer/Winter Net Capability Verification (i.e, Capability Testing) as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21) and submit test results through the eGADs system. As described in M-21, as an alternative to performing the Winter Net Verification, data collected during the summer verification window may be used to satisfy winter test requirements after adjustment to appropriate ambient winter conditions. The purpose of the summer/winter net capability verification is to demonstrate that the unit can achieve the claimed summer/winter net dependable rating of the unit. PJM will use the results of the summer/winter net capability testing to assess whether a unit that was committed to RPM or FRR Alternative was able to achieve at least the Total Unit ICAP Commitment Amount in the summer/winter capability test

A Net Capability Test must be performed during both the Summer and the Winter testing periods. The Summer test period begins the first day of June and ends the last day of August. The Winter test period begins the first day of December and ends on the last day of February. Alternatively, data collected during the summer verification window may be used to satisfy winter test requirements after adjustment to appropriate ambient winter conditions. Hydro generation can be tested any time during the Delivery Year, but is only required to perform net capability verification once per year. If the entire unit is on a forced or planned outage during the entire summer or winter testing period, the unit is expected to submit an out-of-period capability test when the outage ends.

An unlimited number of tests may be performed on the unit during each testing period. If none of the tests certify full delivery of the Total Unit ICAP Commitment Amount, those parties with RPM Resource Commitments and FRR Capacity Plan Commitments from such unit may be subject to Generation Resource Rating Test Failure Charges. Intermittent generation is exempted from the summer/winter capability testing requirement and will not be assessed any Generation Resource Rating Test Failure Charges.

The unit's installed capacity shortfall for the testing period is determined by the test that resulted in the highest installed capacity rating (i.e., the highest Corrected Net Test Capacity as described in PJM's Rules and Procedures for Determination of Generating Capability (M-21)). The Unit ICAP Shortfall for the testing period is equal to the Total Unit ICAP Commitment Amount minus the highest installed capacity rating achieved in the capability test.

A positive shortfall indicates a failure to certify the Total Unit ICAP Commitment Amount during the testing period. A negative shortfall indicates that the Total Unit ICAP Commitment Amount was exceeded during the testing period.

The following business rules apply in the determination of the Unit ICAP Shortfall:

- If a unit is on a partial outage during the test, the amount of the partial outage is added to the highest installed capacity rating in the test to determine the Unit ICAP Shortfall for the summer or winter test period.
- The Unit ICAP Shortfall for the summer testing period will be applied daily for the months of June through November of the Delivery Year. The Unit ICAP Shortfall for

the winter testing period will be applied daily for the months of December through May of the Delivery Year. If the Unit ICAP Shortfall as a result of the winter testing period is less than the Unit ICAP Shortfall as a result of the summer testing period, the Unit ICAP Shortfall as a result of the summer testing period will be applied daily for the months of December through May of the Delivery Year.

- If the entire unit is on a forced or planned outage from June 1 to December 1 of the Delivery Year, a Unit ICAP Shortfall for the summer testing period is not calculated.
- If the entire unit is on a forced or planned outage from December 1 – May 31 of the Delivery Year, the Unit ICAP Shortfall for the winter testing period is the calculated Unit ICAP Shortfall for the summer testing period.
- If the winter rating on a unit is less than the summer rating on the unit and the Total Unit ICAP Commitment Amount is greater than the winter rating, the Unit ICAP Shortfall for the winter testing period will be calculated as the winter rating of the unit (instead of the Total Unit ICAP Commitment Amount) minus the highest installed capacity rating achieved in a winter capability test.
- If a unit is exempt from the winter net capability verification requirement (in accordance with ***Section 6 of PJM Manual 10 – Pre-Scheduling Operations***), the Unit ICAP Shortfall that is calculated as a result of a summer capability test would also apply for the months of December through May of the Delivery Year.
- In the case of hydro generation, the Unit ICAP Shortfall that is calculated as a result of the single capability test submitted is applied for the entire Delivery Year.
- If a daily RPM commitment compliance shortage on a unit occurs due to a unit delay, derating, or retirement during the Delivery Year, the Daily Unit ICAP Shortfall will be reduced by the portion of the daily RPM commitment compliance shortage (in UCAP) due to the unit delay, derating, or retirement divided by one minus the unit's Effective EFORd for the Delivery Year. The Daily Unit ICAP Shortfall for the unit will not be reduced to a value less than zero.

If portions of the unit were committed by multiple Resource Providers, the Daily Unit ICAP Shortfall is allocated to the Resource Providers based on the provider's pro-rata share of the unit's Total Unit ICAP Commitment Amount.

A Provider's Daily ICAP Shortfall for a unit is equal to the Daily Unit ICAP Shortfall times the Provider's Share of Total Unit ICAP Commitment Amount divided by Total Unit ICAP Commitment Amount.

$$\text{Provider's}\,DailyICAPShortfall_{\text{GenResource}} = \frac{DailyUnitICAPShortfall \times \text{Provider's Share of } TotalUnitICAPCommitment}{TotalUnitICAPCommitment}$$

If a Resource Provider has both RPM Resource Commitments and FRR Capacity Plan Commitments on the unit, the Provider's Daily ICAP Shortfall for such unit will be separated into a Daily ICAP Shortfall for RPM Resource Commitments and Daily ICAP Shortfall for FRR Capacity Plan Commitments.

A Resource Provider's Daily ICAP Shortfall for RPM Resource Commitments is equal to the Provider's Daily ICAP Shortfall times the Provider's Average Daily RPM ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$\text{Provider's } DailyICAPShortfall_{RPMResourceCommitments} = \frac{\text{Provider's } DailyUnitICAPShortfall \times \text{Provider's } AverageDailyRPMICAPCommitment}{\text{Provider's } Share\ of\ TotalUnitICAPCommitment}$$

A Resource Provider's Daily ICAP Shortfall for FRR Capacity Plan Commitments is equal to the Provider's Daily ICAP Shortfall times the Provider's Average Daily FRR ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$\text{Provider's } DailyICAPShortfall_{forFRRCapPlanCommitments} = \frac{\text{Provider's } Daily\ Unit\ ICAP\ Shortfall \text{ X Provider's } AverageDailyFRRICAPCommitment}{\text{Provider's } ShareofTotalUnitICAPCommitment}$$

A Resource Provider with a positive Daily ICAP Shortfall will be assessed The Generation Resource Rating Test Failure Charge.

8.4.7 Peak Season Maintenance (PSM) Compliance

To preserve and maintain the reliability of the PJM Region and to recognize the impact of planned outages and maintenance outages during the Peak Season, PJM will perform a Peak Season Maintenance (PSM) Compliance assessment on generation resources committed to the RPM or FRR Alternative. A Resource Provider will be assessed a Peak Season Maintenance (PSM) Compliance Penalty Charge in accordance with ***Attachment DD of the Open Access Transmission Tariff,*** if the provider committed a generation resource to the RPM or FRR Alternative and such resource was not available due to a planned or maintenance outage that occurred during the Peak Season without the approval of PJM. Hydro resources and intermittent resources are exempt from peak-season maintenance compliance assessment and will not be assessed any PSM Compliance Charges.

The Peak Season is defined as the weeks containing the 24th through 36th Wednesdays of the calendar year. All weeks start on a Monday and end on Sunday, except the week with the 36th Wednesday, which ends on a Friday.

If the Summer Net Dependable Rating of the unit on the peak season day minus the amount of capacity that was out-of-service on a planned or maintenance outage on a peak season day without the approval of PJM is less than the Total Unit ICAP Commitment Amount, a PSM Compliance Penalty Charge will be assessed to those parties that have RPM Resource Commitments or FRR Capacity Plan Commitments for such unit.

The Daily Unit PSM Compliance Shortfall is equal to Total Unit ICAP Commitment Amount minus (Summer Net Dependable Rating on peak season day minus the amount of capacity out-of-service on unapproved planned or maintenance outage on a peak season day).

$$DailyUnitPSMComplianceShortfall = TotalUnitICAPCommitment - (SummerNetDependableRating - AmountofCapacityOutofService)$$

If a daily RPM commitment compliance shortage occurs due to a derating during the peak season, the Daily Unit PSM Compliance Shortfall will be reduced by the portion of the daily RPM commitment compliance shortage (in UCAP) due to the derating divided by one minus the unit's Effective EFORd for the Delivery Year. The Daily Unit PSM Compliance Shortfall will not be reduced to a value less than zero.

If portions of the unit were committed by multiple Resource Providers, the Daily Unit PSM Compliance Shortfall (MW) is allocated to the Resource Providers based on the provider's pro-rata share of the Total Unit ICAP Commitment Amount.

The Provider's Daily PSM Compliance Shortfall is equal to the Daily Unit PSM Compliance Shortfall times the Provider's Share of the Total Unit ICAP Commitment Amount divided by the Total Unit ICAP Commitment Amount.

$$\text{Provider's}\,DailyPSMComplianceShortfall = \frac{DailyUnitPSMComplianceShortfall \times \text{Provider'sShareof}\,TotalUnitICAPCommitment}{TotalUnitICAPCommitment}$$

If a Resource Provider has both RPM Resource Commitments and FRR Capacity Plan Commitments on the unit, their Daily PSM Compliance Shortfall will be separated into a Daily PSM Compliance Shortfall for RPM Resource Commitments and Daily PSM Compliance Shortfall for FRR Capacity Plan Commitments.

A Resource Provider's Daily PSM Shortfall for RPM Resource Commitments is equal to the provider's Daily PSM Shortfall times the Provider's Average Daily RPM ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$Provider'sDailyPSMShortfall_{\text{RPM Resource Commitments}} = PRovider'sDailyPSMShortfall \times \text{Provider'sAvgDailyRPMICAPComitment}/Provider'sShareofTotalUnitICAPCommitment$$

A Resource Provider's Daily PSM Shortfall for FRR Capacity Plan Commitments is equal to the Provider's Daily PSM Shortfall times the Provider's Average Daily FRR ICAP Commitment Amount divided by the Party's Share of the Total Unit ICAP Commitment Amount.

$$Provider'sDailyPSMShortfall_{\text{FRR Commitments}} = Provider'sDailyPSMShortfall \times \text{Provider'sAvgDailyFRRICAPCommitment}/Provider'sShareofTotalUnitICAPCommitment$$

8.5 Load Management Event Compliance

Compliance is the process utilized to review resource performance during PJM-initiated Load Management events. The process establishes potential under/over compliance values for each Load Management Resource, both Demand Resources and ILR Resources.

Compliance is evaluated separately by event in each Zone for Demand Resources dispatched by PJM. Response to transmission sub-zonal dispatch is voluntary (meaning there are no penalty charges assessed for non-performance) for 2012/2013 and 2013/2014 Delivery Years. Beginning with the 2014/2015 Delivery Year, response to transmission sub-zonal dispatch becomes mandatory (meaning there are penalty charges assessed for non-performance) if the sub-zone is defined and publicly posted the day before the Load Management event. Response to zonal dispatch is mandatory for the DR product type dispatched within the compliance period of such DR product type for all Delivery Years.

Effective with the 2014/2105 Delivery Year, to the extent a demand resource (i.e., registration) cannot respond, another demand resource of a different resource product type in the same geographic location defined by PJM dispatch instructions with the same designated lead time and comparable capacity commitment may be substituted. Any demand resource used as a substitute during an event will have the same obligation to respond to future event(s) as if it did not respond to such event.

Resource providers are responsible for the submittal of compliance information to PJM through the Load Response system for each PJM initiated Load Management event during the compliance period. For the 2012/2013 and 2013/2014 Delivery Years, registrations that voluntarily responded to a transmission sub-zonal dispatch must submit compliance information in the eLRS system.

PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews.

Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place.

8.5.1 Measuring Event Compliance

PJM verifies Load Management Event Compliance on an end-use customer basis by reviewing the data submitted by the resource provider through the Load Response system. Like the determination of Nominated Values, Compliance is measured differently for each type of Load Management program.

Compliance for Direct Load Control (DLC) programs will consider only the transmission of the control signal. Resource providers are required to report the time period (during the Load Management event) that the control signal was started and stopped. Failure to start the signal by the start of the event and continue the signal for the duration of the event will result in a deficiency for that end-use customer.

Compliance for Firm Service Level (FSL) customers will be determined by comparing actual load during the event to the nominated firm service level. Resource providers must submit load data for all hours of the event and test day and for all days required for PJM to calculate compliance through the Load Response system.

Compliance for Guaranteed Load Drop (GLD) customers will be determined by comparing actual load dropped during the event to the nominated amount of load drop. Resource providers must submit load data for all hours of the event and test day and for all days required for PJM to calculate compliance. Comparison loads must be developed from the guidelines included in **Attachment A of *PJM Manual M-19 Load Data Analysis*,** and note which method was employed.

Load Management customers may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for the incremental load drop below zero.

Compliance is averaged over the full hours of a Load Management event, for each end-use customer or DLC program to determine a Resource Compliance Position for the Load Management event for each dispatched registration. Compliance data is netted for all registrations in the Load Response System that were dispatched.

Resource Compliance Position for a registration is determined as the Nominated Load Reduction Value reported in the Load Response system minus the actual load reduction, where the Nominated Load Reduction Value is capped at the RPM/FRR Commitment for such registration on the day of the event. If multiple registrations are linked to a committed Demand Resource in the eRPM system, the RPM/FRR Commitment for such Demand Resource is allocated to the registrations pro-rata based on the nominated load reduction value of the registrations.

Resource Compliance Positions for a registration that are positive indicate that the registration under complied during the event. Resource Compliance Positions that are negative indicate that the registration over complied during the event.

8.5.2 Load Management Event Compliance Allocation

For each Demand Resource (DR) provider, compliance data will be totaled over all Demand Resource registrations dispatched by zone, to determine the DR Provider's actual zonal load reduction for the event.

For any Load Management event where the actual net load reduction value achieved by a resource provider in a zone is less than the provider's RPM/FRR Resource Commitments in that zone on the day of the event, the net zonal under-compliance MWs will be allocated back to the registration level on an under-compliance ratio share; however, such net zonal under-compliance MWs will be reduced by the total amount of a Provider's Daily RPM/FRR Commitment Shortages in a zone for all their committed Demand Resources that are of the same product type dispatched on the day of the event, before such an allocation occurs. Registrations that were compliant (or over-compliant) in the zone will not be allocated a portion of the net zonal under-compliance.

For any Load Management event where the actual net zonal load reduction value achieved by a resource provider in a zone is greater than the provider's RPM/FRR Resource Commitments in that zone on the day of the event, the net zonal over-compliance will be allocated back to the registration level on an over-compliance ratio share. Registrations that were not over-compliant or did not have a commitment in the zone will not be allocated a portion of the net zonal over-compliance.

Following the allocation, under-compliant registrations will be subject to a Load Management Event Penalty Charge. Over-compliant registrations may be eligible to receive a Load Management Penalty Charge Allocation.

8.6 Load Management Test Compliance

DR Resource providers are subject to Load Management Test Compliance.

If a registration for a Limited Demand Resource is not dispatched by PJM for a Load Management Event prior to August 15th of the Delivery Year, then such registration must demonstrate that it was tested simultaneously with other non-dispatched Limited DR registrations in the zone for a one-hour period during any hour when a PJM Load Management Event may be called between June 1 and September 30th of the Delivery Year. If a registration for a Limited Demand Resource is dispatched by a PJM for a Load Management Event between August 16th and September 30th of the Delivery Year, no load management test is required for such registration. If a registration for Limited Demand Resource committed to PJM is dispatched by PJM for a PJM Load Management event in a transmission sub-zone between June 1 and September 30 of the 2012/2013 and 2013/2014 Delivery Years and such registration performs at or above the nominated amount of capacity on the registration, no test will be required and no Load Management Test Failure Charges will be assessed for such registrations. If a registration for a committed Limited Demand Resource is dispatched by a PJM-initiated Load Management Event in a zone between June 1 and September 30th of the Delivery Year, load management test compliance will not be evaluated and Load Management Test Failure Charges will not be assessed for such registration.

If a registration for a Annual Demand Resource is not dispatched by PJM for a Load Management Event in a Delivery Year, then such registration must demonstrate that it was tested simultaneously with other non-dispatched Annual Demand Resource registrations in the zone for a one-hour period during any hour when a PJM Load Management Event may be called during June through October or the following May of the Delivery Year. If a registration for an Annual Demand Resource is dispatched by PJM for a Load Management Event during the Delivery Year, then no test will be required for such registration and no Load Management Test Failure Charges will be assessed for such registration.

If a registration for an Extended Summer Demand Resource is not dispatched by PJM for a Load Management Event during June through October or the following May in a Delivery Year, then such registration must demonstrate that it was tested simultaneously with other non-dispatched Extended Summer Demand Resource registrations in the zone for a one-hour period during any hour when a PJM Load Management Event may be called during June through October or the following May of the Delivery Year. If a registration for an Extended Summer Demand Resource is dispatched by PJM for a Load Management Event during June through October or the following May of the Delivery Year, then no test will be required for such registration and no Load Management Test Failure Charges will be assessed for such registration.

For those registrations required to test, all of the provider's registrations of the same product type and same zone must test at the same time for a one hour period during any hour when a PJM-initiated load management event for such product type may be called:

- Limited DR: 12:00 PM EPT to 8:00 PM EPT
- Extended Summer DR and Annual DR: 10:00 AM EPT to 10:00 PM EPT

The test must be conducted on a non-holiday weekday during the following testing periods:

- Limited DR: June 1 through September 30th of the Delivery Year
- Extended Summer DR and Annual DR: June 1 through October 31 and May of the Delivery Year

The resource provider must notify PJM of the intent to test 48 hours in advance of the test. A notification of intent to test (or retest) must be submitted in the eLRS system. If a resource provider failed to provide the required load reduction in a zone for such product type by less than 25% of their Summer Average RPM Commitment in the zone for such product type, the resource provider may conduct a retest of the subset of registrations (i.e., end-use customer sites) in the zone for such product type that failed the initial test or a subset of registrations that failed the test where the CSP notifies PJM of each end use customer that will not be retested at least 48 hours prior to conducting the retest. If the CSP elects to not retest a subset of registrations that failed the test, such registrations will maintain the compliance result achieved in the initial test. Retesting must be performed at the same time of day and under approximately the same weather conditions. Any registration affiliated with a failed registration must also participate in the retest even if the registration passed the initial test, unless the CSP elects to maintain the compliance result achieved in the test for such failed registration through advanced notification to PJM as mentioned above. If a registration and its affiliate both failed the test then such registrations must either be included in the retest or excluded from the retest with the necessary advanced notification to PJM. Affiliated registrations are registrations that have any ability to shift load and are owned or controlled by the same entity. If a resource provider failed to provide the required load reduction in a zone for such product type by more than 25% of their Summer Average RPM Commitment in the zone for such product type, retesting only a subset of the registrations that failed the initial test is not permitted.

A Provider's Summer Average RPM Commitment in a zone for such product type is equal to the daily average of the provider's total RPM/FRR resource commitments from June 1st through September 30th of the Delivery Year for such product type.

Multiple tests may be conducted; however, only one test result may be submitted for each end-use customer site in the Load Response System for compliance evaluation. Test data must be submitted in the Load Response System no later than November 14th of the Delivery Year for Limited DR product type. Test data must be submitted on or after June 1 and no later than July 14th after the Delivery Year for the Annual DR and Extended Summer DR product types. Load Management test compliance will be measured in the same manner as load management event compliance. A resource provider with a positive net testing shortfall in a zone for a product type will be assessed a Zonal Load Management Test Failure Charge.

Load Management test compliance will be measured in the same manner as load management event compliance; however, for purposes of Load Management test compliance the Resource Compliance Position for a registration considers the Summer Average RPM/FRR Commitment as opposed to the RPM/FRR Commitment on the day of the event.

Resource Compliance Position for a registration for a test is determined as the Nominated Load Reduction Value reported in the Load Response system minus the actual load reduction, where the Nominated Load Reduction Value is capped at the Summer Average RPM/FRR Commitment for such registration.

Summer Average RPM/FRR Commitment for a Demand Resource is the daily average of the RPM/FRR resource commitments for such Demand Resource from June 1st through September 30th of the Delivery Year. If multiple registrations are linked to a committed Demand Resource in the eRPM system, the Summer Average RPM/FRR Commitment for such Demand Resource is allocated to the registrations pro-rata based on the nominated load reduction value of the registrations.

For any Load Management test, a provider's net testing shortfall in a zone for a product type is calculated as the provider's Summer Average RPM/FRR Resource Commitments in such zone for a product type minus the actual zonal load reduction value achieved by the provider in such zone for such product type. A resource provider with a positive net testing shortfall in a zone for a product type (i.e., under compliance MWs in zone for a product type) will be assessed a Zonal Load Management Test Failure Charge.

8.7 Replacement Resources

Participants may specify replacement resources in order to avoid or reduce resource performance assessment shortfalls and the associated deficiency/penalty charges. Participants may not specify replacement resources in order to avoid or reduce performance assessment shortfalls and associated deficiency/penalty charges related to price responsive demand.

Replacement capacity for generation resources, Demand Resources, Energy Efficiency Resources, or Qualifying Transmission Upgrades committed to RPM may be specified via the eRPM system by entering a "Replacement Capacity" transaction after the EFORd for the Delivery Year has been locked in the eRPM system (November 30 prior to the Delivery Year), but before the start of the Delivery Day.

Through the "Replacement Capacity" transaction functionality in eRPM, PJM will provide participants with a list of the available capacity for each generation or demand resource in their portfolio as well as a list of cleared buy bids from any Incremental Auction via the eRPM system and a list of resources with RPM Resource Commitments. Participants will have the ability to match a generation, Demand Resource, Energy Efficiency Resource or Qualifying Transmission Upgrade resource committed to RPM that they would like to replace with available capacity from a generation resource, demand resource, cleared buy bids in an Incremental Auction, or from Locational UCAP transactions.

The following are business rules that apply to Replacement Resources for Resources Committed to RPM:

- The start date and end date of the replacement must be specified.
- A Replacement Resource used to reduce a Demand Resource commitment shall be specified for no less than the balance of the Delivery Year. An available Demand Resource may only be used as a Replacement Resource when the start date of the Replacement Capacity transaction is from June 1 through September 30th unless the Demand Resource can demonstrate through the prior summer's event or test compliance data that the Demand Resource met both its Summer Average RPM Commitment and the new daily RPM commitment level that would result if the Replacement Capacity transaction was approved.
- The desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced and the replacement resource must be specified. The change in Daily RPM Resource Commitments cannot result in a negative value for the Daily RPM Resource Commitments for the resource being replaced.
- The replacement resource must be located in the same LDA as the resource that is being replaced or reside in the Sink LDA of the Qualifying Transmission Upgrade being replaced.
- Resources located in a constrained LDA can serve as replacement capacity for a generation resource located in a less constrained parent LDA.
- The replacement resource must have the same or better temporal availability characteristics as the resource that is being replaced. For example, Annual Resource commitments can only be replaced by available capacity from an Annual Resource or cleared Buy Bids for Annual Capacity or Locational UCAP originating

from an Annual Resource; Extended Summer DR commitments can be replaced by available capacity from an Annual Resource or Extended Summer DR, or cleared Buy Bids for Annual or Extended Summer Capacity or Locational UCAP originating from an Annual Resource or Extended Summer DR; and Limited DR commitments can be replaced by available capacity from an Annual Resource, Extended Summer DR or Limited DR, or cleared Buy Bids for Annual, Extended Summer or Limited Capacity or Locational UCAP originating from an Annual Resource, Extended Summer DR or Limited DR.

- If a generation, demand, or EE resource is used as replacement capacity, a decrease in the Daily RPM Resource Commitments for the resource that is being replaced will result and a corresponding increase in the Daily RPM Resource Commitments for the replacement generation, demand, or EE resource will result during the time period specified for replacement. A change in the Daily RPM Resource Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.
- If cleared buy bids from an Incremental Auction or Locational UCAP transactions are used as replacement capacity, a decrease in the Daily RPM Commitments for the resource that is being replaced will result during the time period specified for replacement. A change in the Daily RPM Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

Replacement resources for generation, QTU, Energy Efficiency Resources, or Demand Resources committed to FRR Capacity Plan are specified by an FRR Entity through the update of the FRR Entity's FRR Capacity Plan prior to the start of the Delivery Day. FRR Entities may update their FRR Capacity Plan to reduce the FRR Capacity Plan Commitment on the resource being replaced and increase the FRR Capacity Plan Commitment on a replacement resource. The change in the Daily FRR Capacity Plan Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

8.7.1 Excess Commitment Credits

LSEs may receive credits when Reliability Requirements decrease resulting in an excess capacity.

The Excess Capacity Credits will be the PJM Sell Offers in the Scheduled Incremental Auctions that do not clear less the PJM Buy Bids in Incremental Auctions that do not clear. The Excess Capacity Credits in PJM will be allocated to LDAs pro rata based on the reduction in LDA peak load forecast from BRA to the time of Third Incremental Auction, provided the amount allocated does not exceed the reduction in the corresponding LDA Reliability Requirement. There will not be an allocation to LDA with an increase in load forecast.

The amount allocated to LDA will be further allocated to LSEs that are charged a Locational Reliability Charge, based on the Daily Unforced Capacity Obligation of the LSEs as of June 1 of the Delivery Year, and the credits will be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

8.8 Demand Response (DR) Transition Provision for 2012/2013-2014/2015 Delivery Years

Effective with the 2012/2013 Delivery Year, only load reductions below an end-use customer's peak load contribution (PLC) are considered in calculating event/test compliance for guaranteed load drop (GLD) registration. A DR Transition Provision was implemented to provide an interim alleviation provision for Curtailment Service Providers (CSPs) that made commitments in prior RPM Auctions under the prior measurement and verification methodology for GLD programs.

The Transition Provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (i.e., Transition Delivery Years).

A CSP that concludes its Demand Resource cleared in the Base Residual Auction for a Transition Delivery Year is not viable under the revised PLC measurement metric, may seek compensation related to its previously cleared Demand Resource in a Base Residual Auction for such Transition Delivery Year through a DR Capacity Transition Credit or an Alternate DR Transition Credit

A DR Capacity Transition Credit protects a CSP from purchasing more expensive replacement capacity in an Incremental Auction in relation to the Base Residual Auction price. To qualify for a DR Capacity Transition Credit, the CSP must inform PJM in writing no later than 30 days prior to the next scheduled Incremental Auction for the Transition Delivery Year for which the identified Demand Resource cleared. Notifications for the 2013/2014 Delivery Year must be submitted by June 15, 2012 and notifications for the 2014/2015 Delivery Year must be submitted by August 10, 2012.

Such written notification must be submitted to dsr_ops@pjm.com and include Zone, RPM Resource Name, and specify the MW amount of such resource's BRA commitment for which they seek protection. All notifications are subject to PJM review to ensure the CSP is qualified to participate in the DR Transition Provision and approve the maximum MW quantity in an LDA (by product type for the 2014/2015 DY) for which the CSP may seek protection.

The qualified CSP must submit buy bid(s) in any of the remaining Incremental Auctions for the relevant Transition Delivery Year. If the CSP's locational, (product-specific for 2014/2015 Delivery Year) buy bid clears in the Incremental Auction and the Incremental Auction Resource Clearing Price (IA RCP) is greater than the Base Residual Auction LDA Resource Clearing Price (BRA RCP), the CSP shall receive a DR Capacity Transition Credit for such buy bid equal to the price difference between the IA RCP and BRA RCP, multiplied by the lesser of the (approved LDA, product-specific MW quantity, or the cleared buy bid MW quantity).

The cost of DR Capacity Transition Credits for an LDA is included in the relevant Transition Delivery Year's Final Zonal Capacity Prices for such zones in the LDA and is collected from LSEs in the zones of the LDA via the Locational Reliability Charge.

In lieu of receiving a DR Capacity Transition Credit, a CSP may seek compensation related to its previously cleared Demand Resource in a BRA for such Transition Delivery Year through an Alternate DR Transition Credit.

The Alternate DR Transition Credit protects a CSP that is unavoidably obligated to pay an end-use customer and insulates the CSP from losses when unavoidable contractual obligations exceed any gains from buying replacement capacity in Incremental Auctions for the same Delivery Year. To qualify for the Alternate DR Transition Credit, the CSP must inform PJM in writing no later than 30 days prior to the next scheduled Incremental Auction, for the Transition Year for which the identified Demand Resource cleared, regardless of whether or not the CSP plans to participate in the Auction. Notifications for the 2013/2014 Delivery Year must be submitted by June 15, 2012 and notifications for the 2014/2015 Delivery Year must be submitted by August 10, 2012.

Such written notification must be submitted to **dsr_ops@pjm.com** and include Zone, RPM Resource Name, and specify the MW amount of such resource's BRA commitment for which they seek protection. All notifications are subject to PJM review to ensure the CSP is qualified to participate in the DR Transition Provision and approve the maximum MW quantity in an LDA (by product type for the 2014/2015 DY) for which the CSP may seek protection.

The CSP must demonstrate to PJM no later than 60 days prior to the start of the relevant Transition Delivery Year that it has a contract executed on or before April 7, 2011 for which the CSP is unavoidably obligated to pay the end-use customer and that the amounts unavoidably owed under the contract exceeds the CSP's gains on any purchases of replacement capacity in Incremental Auctions for the same Delivery Year.

If the CSP is approved by PJM to qualify for the Alternate DR Transition Credit for a Transition Delivery Year, the CSP must submit monthly reports to PJM that describe the actual amounts paid and received by the CSP. Such reports must be submitted within 15 days following the end of each month of the relevant Transition Delivery Year.

The qualified CSP will receive an Alternate DR Transition Credit in an LDA equal to the aggregate amount the CSP is unavoidably obligation to pay as verified by PJM minus any monetary gains from purchases of replacement capacity. Monetary gains are equal to the aggregate LDA Auction Credits from BRA -- aggregate LDA Auction Charges for all replacement capacity purchased in Incremental Auctions.

The cost of the Alternate DR Transition Credits in an LDA will be allocated to LSEs in the zones of the LDA on a pro-rata basis based on the LSE's daily unforced capacity obligations.

Section 9: Settlements

Welcome to the *Delivery Year Activity* section of the PJM Manual for the *PJM Capacity Market*. In this section, you will find the following information:

- The business rules for the deficiency and penalty charges in RPM/FRR for committed supply resources (see "Deficiency and Penalty Charges")
- The business rules for Locational Reliability Charges (see "Locational Reliability Charges"
- The business rules for RPM auction credits and charges (see "Auction Credits and Charges")
- The business rules for DR Transition Provision Credit and Charges (see "DR Transition Provision Credits and Charges (2012/2103-2014/2015 Delivery Years)"
- The business rules for the penalty charges in RPM/FRR for non-performance of price responsive demand (see "Penalties for Non-Performance of Price Responsive Demand"
- The business rules for the PRD Credits (see "PRD Credits")

9.1 Deficiency and Penalty Charges

9.1.1 Peak-Hour Period Availability Charge

The Peak-Hour Period Availability Charge shall be equal to the Daily Peak-Hour Period Availability Charge Rate * Net Peak Period Capacity Shortfall in an LDA.

$$PeakHourPeriodAvailabilityCharge = DailyPeakHourPeriodAvailabilityChargeRate \times NetPeakPeriodCapShortfall$$

The Daily Peak-Hour Period Availability Charge Rate applied to the Net Peak Period Capacity Shortfalls for RPM Resource Commitments in an LDA is equal to the a party's Weighted Average Resource Clearing Price in an LDA ($/MW-day).

$$DailyPeakHourPeriodAvailabilityChargeRate_{RPM} = WeightedAvgResourceClearingPrice_{inLDA}$$

A party's Weighted Average Resource Clearing Price in an LDA is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by a party's cleared and make-whole MWs in the LDA.

In the case where a Party's Weighted Average Resource Clearing Price in an LDA is equal to $0/MW-day, a PJM Weighted Average Resource Clearing Price in an LDA will be used.

The PJM Weighted Average Resource Clearing Price in an LDA is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by the total cleared and make-whole MWs in the LDA.

The Daily Peak-Hour Period Availability Charge Rate applied to Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in an LDA is equal to the weighted average of the resource clearing prices across all RPM auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

9.1.2 Allocation of Peak-Hour Period Availability Charges

The Peak-Hour Period Availability Charges for RPM Resource Commitments are allocated to those Resource Providers that have a negative Net Peak Period Capacity Shortfalls for RPM Resource Commitments in an LDA. The amount allocated to these Resource Providers is capped at their Net Peak Capacity Shortfall in the LDA times the Daily Peak-Hour Period Availability Charge Rate.

The Peak-Hour Period Availability Charges for FRR Resource Commitments are allocated to those Resource Providers that have a negative Net Peak Period Capacity Shortfalls for FRR Capacity Plan Commitments in an LDA. The amount allocated to these Resource Providers is capped at their Net Peak Capacity Shortfall in LDA times the Daily Peak-Hour Period Availability Charge Rate.

Any remaining balance of Peak-Hour Period Availability Charges is allocated to LSEs who were assessed a Locational Reliability Charge and FRR Alternative LSEs with a resource portfolio that over performed (i.e., FRR LSEs with negative Net Peak Period Capacity Shortfalls). The Peak-Hour Period Availability Charges are allocated to these LSEs on a pro-rata basis based on their daily unforced capacity obligations.

Peak-Hour Period Availability Charges and Credits are assessed daily and billed retroactively for the entire Delivery Year in the September billing cycle after the conclusion of the Delivery Year.

9.1.3 Capacity Resource Deficiency Charge

The Daily Capacity Resource Deficiency Charge is equal to the Daily Deficiency Rate times the Daily RPM Commitment Shortage for generation resource or Demand Resource.

$$DailyCapResourceDeficiencyCharge = DailyDeficiencyRate \times DailyRPMCommitmentShortage$$

The Daily Deficiency Rate ($/MW-day) is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day, a PJM Weighted Average Resource Clearing Price in an LDA will be used.

A party's Weighted Average Resource Clearing Price for such resource is determined by calculating the weighted average of resource clearing prices for such resource across all RPM Auctions, weighted by a party's cleared and make-whole MWs for such resource.

The PJM Weighted Average Resource Clearing Price in an LDA is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by the total cleared and make-whole MWs in the LDA.

Daily Capacity Resource Deficiency Charges are assessed daily and billed weekly.

9.1.4 Transmission Upgrade Delay Penalty Charge

The Daily Transmission Upgrade Delay Penalty Charge is equal to the QTU Delay Penalty Rate times the Daily RPM Commitment Shortage for the QTU.

$$DailyTransUpgradeDelayPenaltyCharge = QTUDelayPenaltyRate \times DailyRPMCommitmentShortage$$

The QTU Delay Penalty Rate is equal to the higher of two times the Locational Price Adder of the LDA into which the QTU is cleared or Net CONE less the Resource Clearing Price in the LDA from which the CETL was increased.

Transmission Upgrade Delay Penalty Charges are assessed daily and billed weekly.

9.1.5 Generation Resource Rating Test Failure Charge

The Daily Generation Resource Rating Test Failure Charge shall be equal to the Daily Deficiency Rate times the Daily ICAP Shortfall times (1 – Effective EFORd) for a generation resource.

$$GenerationResourceRatingTestFailureCharge = DailyDeficiencyRate \times DailyICAPShortfall \times (1 - EffectiveEFORd)$$

The Daily Deficiency Rate applied to a Daily ICAP Shortfall for RPM Resource Commitments is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day, a PJM Weighted Average Resource Clearing Price in an LDA will be used.

The Daily Deficiency Rate applied to a Daily ICAP Shortfall for FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

Generation Resource Rating Test Failure Charges are assessed daily for the entire Delivery Year and are billed retroactively for the entire Delivery Year in the June billing cycle after the conclusion of the Delivery Year.

9.1.6 Peak Season Maintenance Compliance Penalty Charge

The Daily PSM Compliance Penalty Charge is equal to the Daily Deficiency Rate times the Daily PSM Compliance Shortfall times (1- Effective EFORd) for a generation resource.

$$PSMCompliancePenaltyCharge = DailyDeficiencyRate \times DailyPSMComplianceShortfall \times (1 - EffectiveEFORd)$$

The Daily Deficiency Rate applied to a PSM Compliance Shortfall for RPM Resource Commitments is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day, a PJM Weighted Average Resource Clearing Price in an LDA will be used.

The Daily Deficiency Rate applied to a PSM Compliance Shortfall for FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

PSM Compliance Penalty Charges are assessed each day during the peak season that the resource was out-of-service on an unapproved planned or maintenance outage and billed retroactively in the June billing cycle after the conclusion of the Delivery Year.

9.1.7 Load Management Test Failure Charge

The Daily Load Management Test Failure Charge is equal to the test under compliance MWs in the zone for the product type tested times the LM Test Failure Charge Rate.

$$LoadManagementTestFailureCharge = UnderComplianceMW \times DailyLMTestFailureChargeRate$$

A Provider's Under-Compliance MWs in a zone for the product type tested will be reduced by the summer average of the provider's Daily RPM/FRR Commitment Shortages in a zone for all their Demand Resources in the zone that are of the same product type tested.

The Daily Load Management Test Failure Charge Rate is equal to the Provider's Weighted Daily Revenue Rate in such zone for the product type tested plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate in such zone for the product type tested, or $20/MW-day.) In the case where a Provider's Weighted Daily Revenue Rate in such zone for the product type tested is $0/MW-day, a PJM Weighted Daily Revenue Rate in such zone for the product type tested will be used.

Load Management Test Failure Charges are assessed daily and billed monthly (or otherwise in accordance with customary PJM billing practices in effect at the time); provided, however that a lump sum payment may be required to reflect amounts due, as a result of the testing failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

9.1.8 Allocation of Deficiency and Penalty Charges

The Daily Capacity Resource Deficiency Charges, Daily Transmission Upgrade Delay Penalties, Daily Generation Resource Rating Test Failure Charges, and Daily Peak Season Maintenance Compliance Penalty Charges, and Load Management Test Failure Charges are distributed on a pro-rata basis to LSEs who were charged a Daily Locational Reliability Charge for the day in order to compensate for resource adequacy that was not delivered.

Daily Capacity Resource Deficiency Charges, Daily Transmission Upgrade Delay Penalties, Daily Generation Resource Rating Test Failure Charges, and Daily Peak Season Maintenance Compliance Penalty Charges, and Load Management Test Failure Charges are allocated on a pro-rata basis to LSEs based on their daily unforced capacity obligation.

9.1.9 Demand Resource Compliance Penalty Charge

Penalties and rewards are assessed for PJM-initiated events on an event basis, following a compliance review.

A Demand Resource Compliance Penalty Charge is assessed to those Providers with committed registrations that under complied during an event. The Load Management Compliance Charge for an under compliant registration is equal to the under compliance MWs for the dispatched registration in a zone times the Load Management Zonal Compliance Penalty Rate applicable to such dispatched registration in a zone.

$$LoadManagementCompliancePenaltyCharge = UnderComplianceMW \times LMCompliancePenaltyRate$$

The LM Compliance Penalty Charges will not be assessed to registrations that are dispatched on a transmission sub zonal basis for the 2012/2013 and 2013/2014 Delivery Years. Effective with the 2014/2015 Delivery Year, LM Compliance Penalty Charges will not be assessed to registrations that are dispatched on a transmission sub zonal basis unless such subzone is defined and publicly posted the day before the Load Management Event.

The LM Compliance Charges for an event for dispatched registrations in a zone of the Limited DR product type are assessed daily and initially billed in the third billing month after the event occurs (e.g., June events will be initially included in the September bill issued in October). The initial billing for a LM event will reflect the amounts due from the start of the Delivery Year to the last day that it is reflected in the initial billing. The remaining charges for such LM event will be assessed daily and billed monthly through the remainder of the Delivery Year. The LM Compliance Charges for an event for dispatched registrations in a zone of the Annual DR or Extended Summer DR product type are assessed daily and billed by the later of the month of June following such Delivery Year or the third billing month following the Load Management event that gave rise to such charge. The billing for the Load Management event for Annual DR or Extended Summer DR will be in a lump sum and reflect the accrued charges for the entire Delivery Year.

Effective with the 2012/2013 through 2013/2014 Delivery Years, the Daily Load Management Zonal Compliance Penalty Rate per MW-event applicable to a registration is equal to the lesser of (one divided by the actual number of events during the summer period for the dispatched registration in such zone, or 0.50) * Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration. In the case where a Provider's Daily Revenue Rate in such zone for the dispatched registration is equal to $0/MW-day, a PJM Weighted Daily Revenue Rate applicable to such dispatched registration in such zone will be used.

Effective with the 2014/2015 Delivery Year, the LM Compliance Charge for an event for a dispatched registration in a zone for the on-peak period (which includes all hours for which a Limited Demand Resource would be expected to respond) is equal to the lesser of (one divided by the actual number of events during the Delivery Year for the dispatched registration in such zone, or 0.50) * Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration, multiplied by the net under-compliance in such on-peak period for the dispatched registration. In the case where a Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration is equal to $0/MW-day, a PJM Weighted Daily Revenue Rate applicable to such dispatched registration in such zone will be used.

The LM Compliance Charge for an event for a dispatched registration in a zone for the off-peak period (which includes all hours for which a Annual Demand Resource and Extended Summer Demand Resource would be expected to respond, but does not include hours in on-peak period) is equal to 1/52 times * Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration, multiplied by the net under-compliance in such off-peak period for dispatched registration. In the case where a Provider's Weighted Daily Revenue Rate in such zone for the dispatched registration is equal to $0/MW-day, a PJM Weighted Daily Revenue Rate applicable to such dispatched registration in such zone will be used.

If a Load Management Event is comprised of both an on-peak and off-peak period, then such LM Compliance Charge for such event for a dispatched registration will be the higher of the LM Compliance Charge calculated based on the rate applied for the on-peak period and the registration's under-compliance MWs for the event or LM Compliance Charge calculated based on the rate applied for off-peak period and the registration's under-compliance MWs for the event.

The total Load Management Zonal Compliance Deficiency Penalties assessed to the Provider in a Delivery Year is capped at the annual revenue the provider's Demand Resources would receive.

The Demand Resource Compliance Penalty Charges collected from LM Providers with under-compliant registrations for an event are allocated on a pro-rata basis to those LM Providers with committed registrations that provided load reductions in excess of the amount obligated to provide for such event. The total event allocation to each over-performing registration shall not exceed for each committed registration the volume of excess MWs provided by the committed registration during a single event times 1/5 of the provider's weighted daily revenue rate received by the registration dispatched. Any Load Management Compliance Charges for an event collected from under-compliant registrations of the Limited DR product type will be allocated to over-compliant registrations for such event and have the same bill timing as LM Compliance Charges for Limited DR for such event. Any Load Management Compliance Charges for an event collected from under-compliant registrations of the Annual DR or Extended Summer DR product type will be allocated to over-compliant registrations for such event and have the same bill timing as LM Compliance Charges for Annual DR or Extended Summer DR for such event.

Any Demand Resource Compliance Penalty Charges not allocated to over-performing Providers are instead allocated to all LSEs in the RTO based on the LSE's Daily Unforced Capacity Obligation.

Any LM compliance credits to LSEs will have the same bill timing as LM compliance credits to over-performing providers.

9.1.10 Emergency Procedures Charges

The Emergency Procedures Charges outlined in ***Schedule 14 of the Reliability Assurance Agreement*** for refusal to comply or failure to employ all reasonable efforts to comply will remain in effect, and will be assessed in addition to any penalty described here.

9.2 Locational Reliability Charges

9.2.1 Calculation of Locational Reliability Charges

All LSEs pay a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a zone times the applicable Final Zonal Capacity Price.

$$\textit{Locational Reliability Charge} = \textit{DailyUnforced Capacity Obligation} \times \textit{Final Zonal Capacity Price}$$

Each LSE that serves load in a PJM Zone or load outside PJM using PJM resources (Non-Zone Network Load) during the Delivery Year is responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a Zone times the applicable Final Zonal Capacity Price for that Delivery Year.

Locational Reliability Charges are calculated daily and billed weekly during the Delivery Year.

9.3 Auction Credits and Charges

9.3.1 Calculation of Auction Credits

Each generation, demand, or Qualified Transmission Upgrade resource provider that clears a Sell Offer in an RPM Auction will receive an Auction Credit equal to the MW amount that cleared for the resource times the applicable resource's clearing price in the applicable auction.

$$RPM\,Auction\ Credits = MWCleared_{\text{in LDA}} \times ResourceClearingPrice_{\text{in LDA}}$$

The PJM Generation Deactivation Credits received by units with Reliability Must Run (RMR) contracts will be reduced by the Auction Credits received by the RMR unit in a RPM Auction.

If resource provider cannot provide Demand Resource data on individual LDA basis in a Zone with multiple LDAs, Demand Resources will be paid a Weighted Zonal Resource Clearing Price. The Weighted Zonal Resource Clearing Price for a Zone that includes non-overlapping LDAs is the weighted average of the Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Resources Cleared (including make-whole MWs) in each such LDA. If the Zone has a smaller LDA within a larger LDA then the Weighted Zonal Resource Clearing Price is calculated using the smaller LDA and the remaining portion of the larger LDA.

Auction Credits are be calculated daily and billed weekly during the Delivery Year.

9.3.2 Calculation of Auction Charges

Each resource provider that clears a Buy Bid in the First or Third Incremental Auction will receive an Auction Charge (referred to as Resource Substitution Charge in OATT) equal to the MW amount that cleared in the LDA times the Resource Clearing Price in the LDA in the applicable Incremental Auction.

$$RPM\,Auction\ Charges = MWCleared_{\text{in LDA}} \times ResourceClearingPrice_{\text{in LDA}}$$

Auction Charges are calculated daily and billed weekly during the Delivery Year.

9.3.3 Resource Make-Whole Credit

Resource Make-Whole Credit is paid to the marginal resource in an RPM auction as appropriate to ensure the seller is paid the sell offer MW times the sell offer price. Resource Make-Whole Credit is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the RPM Auction.

$$Resourcemake-WholeCredit = (MinMW\ Offered - ClearedMW) \times ResourceClearingPrice_{\text{in LDA}}$$

Resource Make-Whole Credits from the First or Third Incremental Auctions are charged to all cleared buy bids on a pro-rata basis based on the MWs cleared in such auction.

9.3.4 Capacity Transfer Rights Credit

Each Zonal Capacity Transfer Rights (CTRs) owner will receive a daily Zonal CTR Credit equal to the Zonal CTRs owned multiplied by the Zonal CTR Settlement Rate. Zonal CTRs owned include the Zonal CTRs allocated to an LSE and the results of any CTR transfers. The Zonal CTR Settlement Rate is the Total Economic Value of CTRs in Zone ($/day) for all LDAs in which the zone resides as a result of all RPM Auctions for such Delivery Year divided by the maximum LDA CTRs (MWs) allocated to LSEs in a zone.

$$ZonalCTRCredit = ZonalCTRsOwned \times ZonalCTRSettlementRate$$

Each Incremental CTR owner will receive a daily Incremental CTR Credit equal to the Incremental CTRs owned for the LDA multiplied by the LDA Incremental CTR Credit Rate. Credits will be calculated daily and billed weekly during the Delivery Year.

$$IncrementalCTRCredit = IncrementalCTRsOwned \times LDAIncrmentalCTRCreditRate$$

CTR Credits will be calculated daily and billed weekly during the Delivery Year.

9.3.5 Auction Specific MW Transaction Credits and Charges

The Seller of an Auction Specific Capacity Transaction will receive a charge equal to the transaction amount (in MW) times the price associated with the transaction. The price associated with the transaction is a weighted average of the Resource Clearing Prices of the resource-specific, auction-specific Cleared MWs identified in the transaction.

$$SellerCharge = TransactionAmount \times WeightedAverageResourceClearingPrice$$

The Buyer of an Auction Specific MW Transaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction.

$$BuyerCredit = TransactionAmount \times WeightedAverageResourceClearingPrice$$

Charges and Credits for Auction Specific MW Transactions are calculated daily and billed weekly for the duration of the transaction during the Delivery Year.

9.3.6 Capacity Export Charges and Credits

Capacity Export Charge = Export Reserved Capacity * (Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported - Final Zonal Capacity Price for the Zone in which the resource designated for the export is located)

Where, Export Reserved Capacity = Reserved Capacity of Long-Term Firm Transmission Service used for the export.

Capacity Export Credit = Export Customer's Allocated Share * (Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported - the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located)

Where,

Export Customer's Allocated Share = (Unforced Capacity imported) * [Export Reserved Capacity / (Export Reserved Capacity + Unforced Capacity Obligations of all LSEs in the Zone)]

Unforced Capacity imported = Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located =

[(Export Reserved Capacity + Unforced Capacity Obligations of all LSEs in the Zone) – (Unforced Capacity cleared in the Zone)] *

(Ratio, as determined by PJM, of the CETL from the Zone in which the resource designated for export is located to the total CETL into the export interface Zone).

The revenues collected from Capacity Export Charge less the credit provided will be distributed to the LSEs in the export-interface Zone that were assessed Locational Reliability Charge for the delivery year (RPM LSEs) based on their Daily Unforced Capacity Obligations.

9.4 DR Transition Provision Credits and Charges (2012/2013 – 2014/2015 Delivery Years)

9.4.1 DR Transition Credit

A CSP qualified for a DR Transition Credit in accordance with Section 5.14A of Attachment DD of the OATT and Section 8.8 of this manual will receive a DR Transition Credit for a cleared buy bid in Transition Delivery Year's Incremental Auction that is charged an Incremental Auction Resource Clearing Price that is higher than the Base Residual Auction Resource Clearing Price.

The DR Transition Credit associated with a cleared buy bid in an LDA is equal to (IA LDA RCP minus BRA LDA RCP) multiplied by the lesser of (the approved LDA, product-specific MW, or the cleared buy bid MW quantity).

The DR Transition Credits to qualified CSPs are assessed daily and billed weekly in the relevant Transition Delivery Year.

The cost of the DR Transition Credits for an LDA will be allocated to LSEs serving load in the LDA via the LSE's Locational Reliability Charges.

9.4.2 Alternate DR Transition Credit

A CSP qualified for an Alternate DR Transition Credit in accordance with Section 5.14A of Attachment DD of the OATT and Section 8.8 of this manual will receive an Alternate DR Transition Credit.

The Alternate DR Transition Credit received by a CSP in an LDA is equal to the aggregate amount the CSP is unavoidably obligation to pay as verified by PJM minus any monetary gains from purchases of replacement capacity. Monetary gains are equal to the aggregate LDA Auction Credits from BRA – aggregate LDA Auction Charges for all replacement capacity purchased in Incremental Auctions.

The cost of the Alternate DR Transition Credits in an LDA will be allocated to LSEs in the zones of the LDA on a pro-rata basis based on the LSE's daily unforced capacity obligations.

The Alternate DR Transition Credits to CSPs and Alternate DR Transition Charges to LSEs will be assessed daily and retroactively billed monthly during the relevant Transition Delivery Year after PJM verifies the amount that CSP is unavoidably obligated to pay (e.g., June credits/charges will appear in the July monthly bill issued in August).

9.5 Penalties for Non-Performance of Price Responsive Demand

9.5.1 PRD Commitment Compliance Penalty & Credits

A PRD Provider with a positive daily commitment compliance shortfall in a sub-zone/zone for RPM or FRR will be assessed a Daily PRD Commitment Compliance Penalty.

The Daily PRD Commitment Compliance Penalty is equal to the MW shortfall in the Sub-zone/Zone * Delivery Year Forecast Pool Requirement * PRD Commitment Compliance Penalty Rate.

The MW Shortfall in Sub-zone/Zone for RPM is the Daily Nominal PRD Value committed in BRA and/or Third IA by the PRD Provider minus the Daily Nominal PRD Value for RPM determined from approved and effective PRD registrations for such PRD Provider.

The MW Shortfall in Sub-zone/Zone for FRR is the Daily Nominal PRD Value committed for FRR by the PRD Provider minus the Daily Nominal PRD Value for FRR determined from approved and effective PRD registrations for such PRD Provider.

The PRD Commitment Compliance Penalty Rate for a PRD Provider that committed PRD for RPM is equal to PRD Provider's Weighted Final Zonal Capacity Price in $/MW-Day + higher of [0.2 * PRD Provider's Weighted Final Zonal Capacity Price or $20/MW-day].

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in Base Residual Auction and Third Incremental Auction.

The PRD Commitment Compliance Penalty Rate for a PRD Provider that committed PRD for FRR is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

The revenue collected from assessment of the PRD Commitment Compliance Penalty shall be distributed on a pro-rata basis as Daily PRD Commitment Compliance Credit to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

9.5.2 PRD Maximum Emergency Event Compliance Penalty & Credits

A PRD Provider with a positive net event compliance shortfall in a sub-zone/zone for a Maximum Emergency Event is subject to a PRD Maximum Emergency Event Compliance Penalty.

The PRD Maximum Emergency Event Compliance Penalty for the first Maximum Emergency Event is the net event compliance shortfall in zone times * Delivery Year Forecast Pool Requirement * PRD Event Compliance Penalty Rate.

The penalty charge for a subsequent Maximum Emergency Event in the sub-zone/zone shall be assessed only on the portion of the net event compliance shortfall in the sub-zone/zone that exceeds the maximum net event compliance shortfall in any prior Maximum Emergency Events.

The PRD Event Compliance Penalty Rate for RPM PRD is equal to the PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the PRD Provider's Weighted Final Zonal Capacity Price in such Zone or $20/MW-day) times the number of days in the Delivery Year.

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in BRA and Third IA.

The PRD Event Compliance Penalty Rate for FRR PRD is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

PRD Maximum Emergency Event Compliance Penalty shall be assessed daily and billed the later of (i) third billing month following the Maximum Emergency Event or (ii) the month of December of the Delivery Year.

The revenue collected from assessment of the PRD Maximum Emergency Event Compliance Penalty shall be distributed on a pro-rata basis as Daily PRD Maximum Emergency Event Compliance Credit to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

9.5.3 PRD Test Failure Charges & Credits

Each PRD Provider with a positive net testing shortfall in a zone will be assessed PRD Test Failure Charge.

The PRD Test Failure Charge is equal to the net testing shortfall in zone times * Delivery Year Forecast Pool Requirement * PRD Test Failure Charge Rate

The PRD Test Failure Charge Rate for RPM PRD is equal to the PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the PRD Provider's Weighted Final Zonal Capacity Price in such Zone or $20/MW-day) times the number of days in the Delivery Year.

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in BRA and Third IA.

The PRD Test Failure Charge Rate for FRR PRD is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

The PRD Test Failure Charge shall be assessed daily and charged monthly (or otherwise in accordance with customary PJM billing practices in effect at the time); provided, however, that a lump sum payment may be required to reflect amounts due, as a result of a test failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

The PRD Test Failure Charge shall be assessed daily and billed retroactively in the August bill issued in September after the conclusion of the Delivery Year.

The revenue collected from assessment of the PRD Test Failure Charges shall be distributed on a pro-rata basis as Daily PRD Test Failure Credits to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

9.5.4 LSE PRD Credit

The Load Serving Entity (LSE) identified in the PRD registration that is associated with load served under RPM will receive a Daily LSE PRD Credit each day that the PRD registration is effective. The LSE (FRR Entity) identified in the PRD registration that is associated with load served under the FRR Alternative will not receive a Daily LSE PRD Credit.

LSE PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) + (Share of Zonal Nominal PRD Value committed in Third Incremental Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)] .

Where:

Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration * Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration.

Share of Zonal Nominal PRD Value Committed in Third Incremental Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Third Incremental Auction by the PRD Provider of such registration.

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year

When the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction or Third Incremental Auction will be based on the Nominal PRD Values committed and registered in a sub-Zone.

A Load Serving Entity will receive a LSE PRD Credit for each approved Price Responsive Demand registration that is effective and applicable to load served by such Load Serving Entity on a given day. The total daily credit to an LSE in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone for load served by such LSE on a given day. Although the PRD Credit is assessed to the LSE of record in the registration, all PRD performance penalties are assessed to the PRD Provider associated with such registration.

Section 10: eRPM

Welcome to the *eRPM* section of the PJM Manual for the *PJM Capacity Market*. In this section, you will find the following information:

- A description of the PJM eRPM Auction system (see "PJM eRPM Overview").

10.1 Overview

PJM eRPM is an Internet application that allows Market Participants to participate in PJM's RPM Auctions and view load and obligation data. Figure 9.1 presents a conceptual view of the RPM auction subsystems.

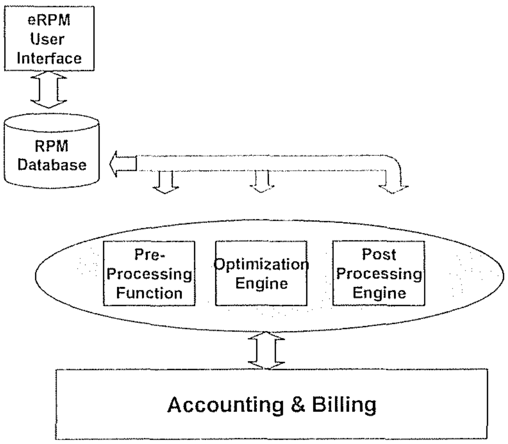

Exhibit 4: RPM Auction Subsystems

The Market User Interface (MUI) allows market participants to:

- Maintain their resource portfolio by increasing or decreasing their installed capacity values for generation, demand resources, and energy efficiency resources via Capacity Modifications, Demand Resource Modifications, and Energy Efficiency Modifications.
- Report Unit Specific Bilateral Transactions with a counterparty
- Report Auction Specific MW Transactions with a counterparty
- Report Locational UCAP Transactions
- Report Cleared Buy Bid Transactions
- Submit Resource Offers to sell capacity into an RPM auction
- Submit replacements for RPM Auction Commitments
- View Auction Results
- View load and obligation data
- View deficiency data related to RPM Auction Commitments

All data entered into the MUI is validated and entered into the RPM database by the MUI.

The RPM auction subsystem consists of the following three components:

- *Pre-processing Function* – performs all activities necessary to setup Auctions, including specifying the Planning Year Parameters as inputs into the solution and evaluating submitted resource offers.
- *Optimization Engine* – performs auction clearing process to ensure the most economical capacity threshold is met. Assigns unit commitments based on the entered offers, demand curves, and specific planning year parameters.
- *Post-processing Function* -- ensures that the appropriate data items are transferred to the RPM auction database for posting on the MUI and ensures the results are transferred to the accounting and billing subsystems.

Section 11: Fixed Resource Requirement Alternative

Welcome to the *Fixed Resource Requirement Alternative* section of the PJM Manual for the *PJM Capacity Markets*. In this section, you will find the following information:

- An overview of the Fixed Resource Requirement Alternative (see "Overview of the Fixed Resource Requirement Alternative")
- The business rules for determining Load Obligations in FRR (see "Load Obligations")
- The business rules for creating the Capacity Plan in FRR (see "Capacity Plan")
- The business rules for supply resources in the FRR Alternative (see "Supply Resources in the FRR Alternative"
- The business rules for locational constraints in the FRR Alternative (see "Locational Constraints in the FRR Alternative")
- The conditions on sales by FRR Entities (see "Conditions on Sales by FRR Entities")
- The business rules for Delivery Year Activity (see "Deliver Year Activity")
- The business rules for the calculation of deficiency charges and penalties (see "Deficiency Charges and Penalties")
- The business rules for the allocation of deficiency charges (see "Allocation of Deficiency Charges")
- The business rules for Auction Specific MW Transactions (see "Auction Specific MW Transactions"

11.1 Overview

11.1.1 Definition and Purpose of Fixed Resource Requirement Alternative

The purpose of the Fixed Resource Requirement (FRR) Alternative is to provide a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

The FRR Alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Base Residual Auctions and the Incremental Auctions; however, such LSE is required to submit a FRR Capacity Plan to satisfy the unforced capacity obligation for all loads in an FRR Service Area, including all expected load growth in the FRR Service Area.

An LSE serving load in an FRR Service Area under the FRR Alternative does not pay an RPM Locational Reliability Charge. The portions of capacity resources included in an LSE's FRR Capacity Plan do not receive any RPM Resource Clearing Prices.

11.1.2 Implementation of the FRR Alternative

PJM's Planning Period is defined as an annual period from June 1 to May 31. The Delivery Year is the Planning Period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012-May 31, 2013 Planning Period.

11.1.3 Participation in the FRR Alternative

An LSE may participate in the Fixed Resource Requirement (FRR) Alternative and avoid participation in RPM, only if the LSE meets the eligibility requirements of the Fixed Resource Requirement (FRR) Alternative as defined in Schedule 8.1 of the Reliability Assurance Agreement (RAA).

To elect the FRR Alternative, an LSE must notify PJM of such election in writing at least two months before the conduct of the Base Residual Auction (BRA) for the first Delivery Year that such election is to be effective.

The election of the FRR Alternative shall be for a minimum term of five consecutive Delivery Years.

The written election notification must provide adequate information to demonstrate that the LSE meets the eligibility requirements of the FRR Alternative and that the FRR Service Area identified to be served by the LSE under the FRR Alternative complies with the meaning of an FRR Service Area as defined in the RAA. The written election must also indicate whether or not the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such capacity resources in any RPM Auctions or as replacement resources in RPM or whether the LSE intends to serve load in another area under RPM.

Within ten business days of the receipt of the written election notification, PJM will validate that the LSE meets the eligibility requirements of the FRR Alternative. PJM will also request confirmation from the EDC that the identified FRR Service Area is metered and complies with the meaning of an FRR Service Area as defined in the RAA. PJM will (1) notify such LSE in writing that its election of the FRR Alternative is valid and the appropriate modifications to the eRPM database have been completed to allow the LSE to submit a FRR Capacity Plan through the eRPM system or (2) notify an LSE in writing that its election of the FRR Alternative is invalid since it did not meet the eligibility requirements of the FRR Alternative or that the identified FRR Service Area does not comply with the meaning of an FRR Service Area as defined in the RAA.

If PJM has provided written notice to an LSE that its election of the FRR Alternative is invalid, the LSE will be required to serve its load under the RPM for the Delivery Year such election was to be effective.

If PJM has provided written notice to an LSE that its election of the FRR Alternative is valid, an LSE must submit its initial FRR Capacity Plan through the eRPM system at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year that such election is to be effective.

An LSE may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum term of five consecutive Delivery Years. Written notice of such termination must be provided to PJM no later than two months prior to the Base Residual Auction (BRA) for such Delivery Year.

An LSE that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

In the event of a State Regulatory Structural Change as defined in the RAA, an LSE may elect or terminate its election of the FRR Alternative effective as to any Delivery Year by providing written notice to PJM of the election or termination of FRR Alternative. The written notice shall be provided in good faith as soon as the LSE becomes aware of such State Regulatory Change, but no later than two months prior to the BRA for such Delivery Year.

To facilitate the election and notices required by the FRR Alternative, the following information shall be posted by PJM by February 1 prior to the conduct of RPM's Base Residual Auction for the Delivery Year:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Short-Term Resource Procurement Target
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd
- Forecast Pool Requirement (FPR)
- Demand Resource (DR) Factor
- Reliability Requirements of the PJM Region and each modeled LDA
- Variable Resource Requirement (VRR) Curves of the PJM Region and each modeled LDA
- CETO and CETL values for each modeled LDA
- Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements for the PJM Region and each Modeled LDA (for the 2014/2015 Delivery Year and beyond)
- Transmission Upgrades projected to be in service for the Delivery Year
- Cost of New Entry (CONE) for the PJM Region and each modeled LDA
- Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
- Base Zonal FRR Scaling Factor
- Percentage of Internal Resources Required in an LDA
- Deadline for FRR Capacity Plan Submittal
- Auction Credit Rate
- LSEs electing the FRR Alternative will be subject to the same credit requirements as suppliers of resources into the RPM auctions, to the extent that they submit as part of their FRR Capacity Plan any resources for which credit would be required if offered into an RPM auction.
- Any credit provided by an LSE to satisfy its credit requirements under the FRR Alternative must be established prior to the deadline for submitting the FRR Capacity Plan.

11.2 Load Obligations

Similar to RPM load obligations, FRR load obligations are calculated in two steps. First, prior to the RPM Base Residual Auction based on Preliminary Zonal Peak Load Forecast; then prior to the Third Incremental Auction based on the Final Zonal Peak Load Forecast. Base and Final Zonal FRR Scaling Factors and Forecast Pool Requirement are used in calculating the FRR Entity Unforced Capacity Obligations.

11.2.1 Preliminary Unforced Capacity Obligation

PJM will notify the Electric Distribution Company (EDC) that an election of the FRR Alternative was made by an LSE in their zone within two business days of the receipt of the written election notification.

An approved FRR Service Area will become a defined "area" within a zone in the eRPM system.

Only one LSE shall be responsible for serving the entire load in an FRR Service Area.

The Electric Distribution Company (EDC) is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year and providing to PJM a Base Obligation Peak Load allocation for the FRR Service Area(s) in their zone within five business days of the receipt of notice of an FRR Service Area within their zone.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area in a zone equals the LSE's Base Obligation Peak Load in the zone/area * the Base Zonal FRR Scaling Factor * the Forecast Pool Requirement.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area shall be reduced by the Nominal PRD Value associated with such load that was approved by PJM in advance of the BRA for such Delivery Year, multiplied by the BRA Forecast Pool Requirement.

The Base Zonal FRR Scaling Factor is equal to Preliminary Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year. The Base Zonal FRR Scaling Factor is posted by February 1 three years prior to the Delivery Year.

The EDC is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer one year prior to the Delivery Year and providing to PJM a Final Obligation Peak Load allocation for the FRR Service Area(s) in their zone by December 31 prior to the start of the Delivery Year.

The Final Zonal FRR Scaling Factor is equal to Final Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the summer one year prior to the Delivery Year. The Final FRR Zonal Scaling Factor is posted by PJM by February 1 prior to the Delivery Year.

The following parameters used in the determination of FRR load obligations are determined in accordance with Section 2 of this manual: Preliminary and Final Zonal Peak Load Forecasts, Zonal Weather Normalized Summer Peaks, Forecast Pool Requirement (FPR), Installed Reserve Margin (IRM), and Pool-wide Average EFORd.

11.2.2 Treatment of Non-Zone Load

Treatment of Non-Zone Load is similar to the treatment under RPM. The FRR Alternative is available to an LSE serving Non-Zone Load if the LSE meets the eligibility and election requirements of the FRR Alternative.

Non-Zone Load is the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

Non-Zone Load may be Non-Zone Network Load (Tariff 1.27B) that is charged a Network Integration Transmission Service (NITS) charge (Tariff Attachment H-A) or other load that may be 'grandfathered' from the NITS charge.

PJM forecasts the Preliminary Non-Zone Load for the RPM Delivery Year and includes it in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load of the Zone from which the Non-Zone Load is served, by February 1 prior to the Base Residual Auction.

To serve Non-Zone Load in a Delivery Year under the Fixed Resource Requirement Alternative, the Non-Zone Load should be included in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load prior to the RPM Base Residual Auction for the Delivery Year. In addition, the LSE must satisfy the eligibility and election requirements of the FRR Alternative.

PJM forecasts the final forecast of the Non-Zone Load and includes it in the Final RTO Forecast Peak Load and the Final Zonal Forecast Peak Load that is posted one month prior to the Third Incremental Auction.

EDC that is responsible to determine the Obligation Peak Loads for the Zone will also establish the Obligation Peak Load associated with the Non-Zone Load by December 31 prior to the start of the Delivery Year.

The LSE serving the Non-Zone Load under the FRR Alternative will be responsible to commit resources in their FRR Capacity Plan to cover the non-zone load.

11.2.3 Annexation & Switching of Load

The following business rules address the annexation of service territory by a Public Power Entity and load switching between FRR Entity and RPM LSEs. If an LSE that is a Public Power Entity annexes service territory to include new customers on sites where no load had previously existed, the incremental load will be treated as unanticipated load growth, and the LSE must commit additional resources to cover the additional load obligation associated with this annexed load.

If an LSE that is a Public Power Entity annexes service territory and the load was already included in the Base Residual Auction, the LSE cannot cover the incremental load obligation using the excess of resources from their FRR Capacity Plan. Instead, the LSE will pay the RPM Locational Reliability Charge for this incremental load obligation (including any additional demand curve obligation) since RPM process has already procured capacity resources to cover this load. The charges collected from the LSE will be used to pay capacity resources that that cleared in the Base Residual Auction for that LDA.

If an LSE that is a Public Power Entity annexes service territory and the Base Residual Auction was not held, the LSE must commit resources to cover this incremental load obligation in its FRR Capacity Plan.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE after the Base Residual Auction, the shifted load will be considered as unanticipated load growth for purposes of determining whether to hold the RPM Second Incremental Auction. If a Second Incremental Auction is held, the FRR LSE will have a must offer requirement for sufficient capacity to meet the load obligation of the shifted load. If no Second Incremental Auction is held, the FRR LSE may sell its excess capacity into RPM Auction or bilaterally.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE and the Base Residual Auction has not been conducted for a Delivery Year, the FRR LSE should no longer commit capacity resources for the shifted load in its FRR Capacity Plan. PJM will include the shifted load in the future Base Residual Auctions.

11.3 Capacity Plan

The most important requirement in electing FRR Alternative is for the FRR Entity to commit Capacity Resources to meet their daily unforced capacity obligations, any applicable Percentage of Internal Resources Required in an LDA, plus any additional threshold if the FRR Entity plans to sell capacity. Failure to commit the required resources would result in FRR Commitment Insufficiency Charge and ineligibility to continue the FRR Alternative. An FRR Capacity Plan is the long-term plan for the commitment of Capacity Resources to satisfy the daily zonal unforced capacity obligations of an LSE that has elected the FRR Alternative in an FRR Service Area and any applicable Percentage of Internal Resources Required in a Locational Deliverability Area (LDA).

If the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such a resource in any RPM Auctions or as a replacement resource in RPM, the LSE must also maintain a Threshold Quantity in its FRR Capacity Plan prior to the Delivery Year.

The Threshold Quantity is equal to the Preliminary Daily Unforced Capacity Obligation plus the lesser of (a) 0.03 * Preliminary Daily Unforced Capacity Obligation or (b) 450 MW.

An LSE must submit an initial FRR Capacity Plan at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year by demonstrating that it has sufficient capacity resources in its FRR resource portfolio in eRPM to satisfy:

- LSE's Preliminary Daily Unforced Capacity Obligations by zone for its FRR Service Area;
- any applicable Percentage of Internal Resources Required in LDA;
- the Minimum Annual Resource Requirement and Minimum Extended Summer Resource Requirement; and
- Threshold Quantity, if applicable.

If the initial FRR Capacity Plan does not satisfy the LSE's Preliminary Daily Zonal Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted Deadline for FRR Capacity Plan Submittal, the LSE's election of the FRR Alternative will not be approved by PJM. The LSE will be required to serve its entire load in the FRR Service Area under the RPM for the Delivery Year such election was to be effective.

An LSE must annually demonstrate through the eRPM system no later than one month prior to the Base Residual Auction for each succeeding Delivery Year that it has extended the commitment of sufficient capacity resources to satisfy:

- LSE's Preliminary Daily Unforced Capacity Obligations by zone for its FRR Service Area;
- any applicable Percentage of Internal Resources Required in LDA;
- the Minimum Annual Resource Requirement and Minimum Extended Summer Resource Requirement; and
- Threshold Quantity, if applicable.

If the FRR Capacity Plan for a succeeding Delivery Year does not satisfy the LSE's Preliminary Daily Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted Deadline for FRR Capacity Plan Submittal, the LSE will be assessed an FRR Commitment Insufficiency Charge for any shortage of unforced capacity in meeting the Percentages of Internal Resources Required in LDA or the Preliminary Daily Unforced Capacity Obligations (including any Threshold Quantity) for any remainder of the minimum term of the FRR election. The FRR Commitment Insufficiency Charge in a zone is equal to two times the Cost of New Entry ($/MW-Year) in the zone times the shortage of unforced capacity resources in meeting the obligation. The shortage is defined as the shortage in meeting the Percentage of Internal Resources Required in LDA plus any additional shortage in meeting the Preliminary Daily Unforced Capacity Obligation including any Threshold Quantity Requirement. The shortage amount identified in the first delivery year that this charge is to be assessed is to be applied in the remaining delivery years that the charge is to be assessed.

FRR Commitment Insufficiency Charges are allocated on a pro-rata basis to all other LSEs (including RPM LSEs) in the RTO based on their Daily Unforced Capacity obligations.

Existing generation, planned generation, bilateral contracts for unit-specific capacity resources, existing demand resources, planned demand resources, and energy efficiency resources may be used in the FRR Capacity Plan if these products meet the requirements specified in the PJM Agreements and Business Rules.

Existing generation that is located outside of the PJM market footprint may be used in the FRR Capacity Plan if the external generation meets the requirements specified in PJM Agreements and Section 4 of this manual.

At the FRR Entity's election, the UCAP MW quantity of generation resources that are committed to the initial FRR Capacity Plan will be determined using the lower of the generation resources' EFORd calculated based on outage data for the 12 months ending September 30th prior to the Base Residual Auction or the 5 Year Average EFORd based on outage data for the 12 months ending September 30th prior to the Base residual Auction.

At the FRR Entity's election and only for the purposes of evaluation of the initial FRR Capacity Plan, the 5 Year Average EFORd for a generation resource having an effective

EFORd of 25% or higher may be recalculated excluding outage data for the most recent one year period.

The EFORd applied to the Final FRR Capacity Plan evaluated prior to the Delivery Year will be determined by PJM using the forced outage data for the 12 months ending September 30th prior to the Delivery Year.

Qualifying Transmission Upgrades may be used to reduce the Percentage of Internal Resources Required in an LDA for the FRR LSE if the Qualifying Transmission Upgrade meets the requirements specified in the PJM Agreements and Section 4 of this manual.

A capacity resource used in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit-specific.

An LSE's FRR Capacity Plan for the Delivery Year shall not include any capacity resource that cleared in any RPM Auction for such Delivery Year.

Any capacity resource that was not offered or offered but did not clear in any RPM Auction for such Delivery Year may be included in an FRR Capacity Plan.

An LSE's FRR Capacity Plan for the Delivery Year may include resources that are committed for less than a full Delivery Year; however, the FRR Capacity Plan in aggregate must satisfy all obligations for the Delivery Year.

If an LSE has committed capacity to meet a Threshold Quantity, the LSE shall maintain such resources until the Delivery Year's Final Unforced Capacity Obligation and final requirements (Percentage of Internal Resources Required in LDA, Minimum Annual Resource Requirement, and Minimum Extended Summer Resource Requirements) are known. The LSE may use such resources during the Delivery Year to meet any increased capacity obligation resulting from an increase in Final Obligation Peak Load from Base Obligation Peak Load, or sell the resources to another FRR Entity in PJM or to an External Party.

All generation resources that have a FRR Capacity Plan Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources must be registered to participate in the Full Program Option of the Emergency Load Response Program and thus be available for dispatch during PJM-declared emergency event.

11.4 Supply Resources in the FRR Alternative

The supply resources available and the qualification requirements for use in FRR Capacity Plans are very similar to RPM resources.

11.4.1 Resource Portfolio

An FRR Entity must specify through the eRPM system, before the FRR Capacity Plan Submittal Deadline, the amounts of installed capacity from resources in their eRPM resource portfolio that are being committed to their FRR Capacity Plan for the Delivery Year.

A party's Daily Generation Resource Position is calculated dynamically by the eRPM system for each unit and is equal to the Daily ICAP Owned on a unit multiplied by one minus the unit's Effective EFORd.

The Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

The Installed Capacity (ICAP) Value of a unit is based on the summer net dependable rating of the unit as determined in accordance with PJM's Rules and Procedures for the Determination of Generating Capability.

The EFORd of a unit is based on forced outage data from an October through September period.

If a unit does not have a full one-year history of forced outage data, the EFORd will be calculated using class average EFORd and the available history as described in the Reliability Assurance Agreement, Schedule 5, Section B.

New units are initially assigned a class average EFORd.

The class average EFORds that are used by PJM to calculate a unit's EFORd are posted to the PJM website by November 30 prior to the Delivery Year.

The Effective EFORd is the EFORd that is effective for the delivery day in the eRPM system.

Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the eRPM system.

During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year.

The EFORd that is effective for the Delivery Year is considered locked in the eRPM system by November 30 prior to the execution of the Third Incremental Auction.

A unit that is in a party's Generation Resource portfolio in eRPM may be committed to FRR Capacity Plan if the party has Daily Available ICAP to commit from the unit for the entire term of the commitment specified in the FRR Capacity Plan.[11] If the party's Daily Available ICAP for the unit varies for the term of the commitment specified in the FRR Capacity Plan, only the minimum Daily Available ICAP may be committed for the term of the commitment specified in the FRR Capacity Plan.

For a party, the Daily Available ICAP to commit on a unit is equal to Daily ICAP Owned - (Daily RPM Resource Commitments/(1-Effective EFORd)) – Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity, approved locational UCAP transactions, and the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific generating unit are equal to the total amount of installed capacity that was committed from the unit for the FRR Capacity Plan.

A party's Daily FRR Generation Resource Position for a specific unit is calculated by multiplying the Daily FRR Capacity Plan Commitments by (1-Effective EFORd).

[11] The term of the resource's commitment to the FRR Capacity Plan may be less than a Delivery Year.

An LSE's Daily Total FRR Generation Resource Position is calculated by summing the Daily FRR Generation Resource Positions of all units in their resource portfolio in eRPM.

An LSE's Daily LDA FRR Generation Resource Position is calculated by summing the Daily FRR Generation Resource Positions of all units in the LDA.

A party's Daily Nominated DR Value for a specific demand resource is equal to the Daily Nominated DR Value as determined by party's "Provisionally Approved" or "Approved" DR Modifications.

A party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the eRPM system and is equal to the Daily Nominated DR Value * DR Factor * Forecast Pool Requirement.

A Demand Resource that is in a party's Demand Resource portfolio may be committed to the FRR Capacity Plan, if there is Daily Available ICAP to commit from the Demand Resource for the entire term of the commitment specified in the FRR Capacity Plan.

For a party, the Daily Available ICAP for a specific demand resource is equal to the resource's Daily Nominated DR Value ((Daily RPM Resource Commitments/(DR Factor *Forecast Pool Requirement)) – Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such demand resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources, approved unit specific transactions for cleared capacity, and approved locational UCAP transactions.

A party's Daily FRR Capacity Plan Commitments for a specific demand resource are equal to the total amount of Nominated DR that was committed from the Demand Resource for the FRR Capacity Plan.

A party's Daily FRR Demand Resource Position for a specific demand resource is equal to Daily FRR Capacity Plan Commitments* DR Factor* Forecast Pool Requirement.

A LSE's Daily Total FRR Demand Resource Position is equal to the sum of the Daily FRR Demand Resource Position of all demand resources in their resource portfolio in eRPM.

A LSE's Daily LDA FRR Demand Resource Position is calculated by summing the Daily FRR Demand Resource Positions of all demand resources in the LDA.

A party's Daily FRR Capacity Plan Commitments for a specific EE Resource are equal to the total amount of Nominated EE that was committed from the EE Resource for the FRR Capacity Plan.

A party's Daily FRR EE Resource Position for a specific EE Resource is equal to Daily FRR Capacity Plan Commitments* DR Factor* Forecast Pool Requirement.

A LSE's Daily Total FRR EE Resource Position is equal to the sum of the Daily FRR EE Resource Position of all EE resources in their resource portfolio in eRPM.

A LSE's Daily LDA FRR EE Resource Position is calculated by summing the Daily FRR EE Resource Positions of all EE resources in the LDA.

An LSE's Daily Total FRR Resource Position is calculated by summing the Daily FRR Generation Resource Positions, Daily FRR Demand Resource Positions, and Daily FRR EE Resource Positions of all resources in their eRPM resource portfolio.

After the FRR Capacity Plan Submittal Deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Preliminary Unforced Capacity Obligation to determine if the LSE has satisfied their Preliminary Unforced Capacity Obligation for the entire Delivery Year.

After the FRR Capacity Plan Submittal Deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Threshold Quantity, if applicable, to determine if the LSE has satisfied their Daily Threshold Quantity for the entire Delivery Year.

During the Delivery Year, an LSE's Daily Total FRR Resource Position is compared to their Daily Final Unforced Capacity Obligation to determine if a Capacity Resource Deficiency Charge is to be assessed.

An LSE's Daily LDA FRR Resource Position is calculated by summing the Daily LDA FRR Generation Resource Positions, Daily LDA FRR Demand Resource Positions, and Daily LDA FRR EE Resource Positions of all resources in their RPM resource portfolio.

After the FRR Capacity Plan Submittal Deadline, an LSE's Daily LDA FRR Resource Position is compared to Amount of Internal Resources Required in the LDA to determine if the LSE has satisfied the Percentage of Internal Resources Required in the LDA for the entire Delivery Year.

During the Delivery Year, an LSE's Daily LDA FRR Resource Position is compared to the Amount of Internal Resources Required in the LDA to determine if a Capacity Resource Deficiency Charge is to be assessed.

11.4.2 Existing Generation

Existing generation located within the PJM region or outside the PJM region is eligible to be committed to the FRR Capacity Plan if it meets the requirements set forth in Section 4 of this manual.

11.4.3 Planned Generation

Planned generation located within the PJM region or outside the PJM region is eligible to be committed to the FRR Capacity Plan if it meets the requirements set forth in Section 4 of this manual.

11.4.4 Capacity Modifications (Cap Mods)

RPM Business Rules regarding Capacity Modifications in Section 4 of this manual apply to the FRR Alternative.

CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and "Provisionally Approved" in the eRPM system in order for the CAP MODs to be considered in a party's Daily Generation Resource Position and the calculation of Available ICAP to commit to the FRR Capacity Plan.

If the status of a "Provisionally Approved" CAP Mod changes to "Denied" or "PJM Withdrawn" all bilateral transactions for the unit will be changed from "Approved" to

"Denied". There will be no change to any party's RPM Resource Commitments; however, there may be a change to a party's FRR Capacity Commitments.

11.4.5 Bilateral Unit-Specific Transactions

RPM Business Rules regarding Bilateral Unit-Specific Transactions in Section 4 of this manual apply to the FRR Alternative.

Available or Unoffered installed capacity purchased through a bilateral unit-specific transaction that is reported via PJM's eRPM system may be committed to an FRR Capacity Plan.

All unit-specific bilateral transactions that are in the "Provisionally Approved" or "Approved" status in the eRPM system will be considered in a party's Daily Generation Resource Position and the calculation of Daily Available ICAP to commit.

The Capacity Export Charge and Credit described in Section 4: Supply Resources in the Reliability Pricing Model, under BILATERAL TRANSACTIONS and in Section 9: Settlements are applicable to resources owned by FRR Entities also.

11.4.6 Qualified Transmission Upgrade

A Qualified Transmission Upgrade may be included in an LSE's FRR Capacity Plan. Such a transmission upgrade must be approved and assigned an incremental import capability value into the constrained LDA by the PJM Planning Department at least 45 days prior to deadline for submitting the initial FRR Capacity Plan for the Delivery Year.

An approved Qualified Transmission Upgrade may be used to reduce the Amount of Internal Capacity Required in the LDA for the FRR LSE.

The planned transmission upgrade in-service date must be on or before the start of the Delivery Year.

At a minimum, a facilities study agreement must be executed for the proposed transmission upgrade, in order for approval to be granted and the transmission upgrade must conform to all applicable standards of the PJM Regional Transmission Expansion Planning Process.

If a Qualified Transmission Upgrade is not completed by the start of the Delivery Year, the LSE who included the upgrade as part of their FRR Capacity Plan for the Delivery Year shall provide a replacement in the form of an equivalent amount of capacity resource capability within the applicable LDA by the start of the delivery Year. If replacement capacity is not provided, a Capacity Resource Deficiency Charge may apply.

11.4.7 Load Management Products

A Load Management program (e.g., Direct Load Control, Firm Service Level, or Guaranteed Load Drop program) is eligible to be committed as a Demand Resource (DR) to the FRR Capacity Plan, if the program meets the requirements specified in the Load Data Systems Manual (M-19) and Section 4.3 of this manual.

In order to commit a Demand Resource to the initial FRR Capacity Plan for a Delivery Year, an FRR Entity must submit no later than 15 business days prior to the initial FRR Capacity Plan submittal deadline a completed DR Plan template (i.e., the DR Sell Offer Plan template described in Attachment C of this Manual). The completed DR Plan template must clearly identify in the Summary section the Existing Nominated DR Value or Planned Nominated DR Value in ICAP MWs that the FRR Entity intends to commit to their initial FRR Capacity Plan. Actual deadline date for the DR Plan template is provided in the RPM Auction Schedule posted on the pjm website.

If an FRR Entity intends to commit demand resources located in a pre-identified zone/sub-zone, PJM will grant conditional approval of the total Nominated DR Value in such zone/sub-zone pending the PJM review of DR Sell Offer Plans for the Base Residual Auction for such Delivery Year.

An FRR Entity with PJM approved or conditionally approved Nominated DR Value(s) in zone/sub-zone(s) will be permitted to commit the associated Demand Resource(s) to the FRR Capacity Plan, provided credit has been posted with the PJM Treasury Department for any Planned Demand Resource(s).

If a review of the DR Sell Offer Plans for the Base Residual Auction for such Delivery Year reveals that any of the conditionally approved MWs in a pre-identified zone/sub-zone are ascribed to another CSP by a letter of support from an end-use customer, such MWs shall be uncommitted from the FRR Capacity Plan and additional capacity resources shall be committed by the FRR Entity to the FRR Capacity Plan to satisfy the FRR Entity's Preliminary Unforced Capacity Obligation.

The UCAP value of a Demand Resource is the Nominated DR Value * DR Factor * Forecast Pool Requirement. (The DR Factor was formerly known as the ALM Factor).

The Nominated DR Value for a load management program cannot exceed the maximum value determined in accordance with the ***Load Data Systems Manual (M-19)***.

A resource provider who has FRR Capacity Plan Commitments for their demand resource must provide (or contract with another party to provide) the following during the Delivery Year:

> Supplemental status reports, detailing Load Management availability, as requested by PJM System Operations in accordance with the PJM Manuals;
>
> After each PJM-initiated Load Management event, customer-specific compliance and verification information within 45 days after the end of the month in which the event occurred, in accordance with Load Data Systems Manual (M-19);
>
> Load drop estimates for all Load Management events (whether initiated by PJM or the resource provider) at the end of each season, in accordance with the Load Data Systems Manual (M-19).
>
> A resource provider who has FRR Capacity Plan Commitments for their demand resource will be subject to the Load Management Event Compliance and Load Management Test Compliance in accordance with Section 8 of this manual.

11.4.8 Demand Resource Modifications (DR MODs)

RPM Business Rules for DR MODs in Section 4 of this manual apply to the FRR Alternative.

DR MODs must be in a "Provisionally Approved" or "Approved" status in order for the DR MOD to be considered in a party's Demand Resource Position and in the calculation of Available ICAP to commit to the FRR Capacity Plan.

Once all approved registrations for relevant Delivery Year have been received by PJM, a DR MOD increase/decrease for the Demand Resource will be entered by PJM in eRPM if the nominated value of the Demand Resource in a zone/area increases/decreases due to an increase/decrease in Peak Load Contribution values and/or due to changes in EDC Loss Factors. This DR MOD will be submitted and approved by PJM in the eRPM system in order to be reflected in a party's Demand Resource position for the relevant Delivery Year. A DR Mod decrease may result in the reduction of FRR Capacity Plan Commitments.

11.5 Energy Efficiency Resources

An EE Resource may commit to an FRR Capacity Plan for a maximum of up to four consecutive Delivery Years. The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year. The time period of Energy Efficiency installations and their associated eligibility, in addition to the modeling of EE Resources in the PJM Capacity Market, is presented in ***PJM Manual 18B: Energy Efficiency Measurement &Verification,***

An EE Resource must meet the following minimum requirements:

- Submit Initial Measurement &Verification (M&V) Plan no later than 30 days prior to the FRR Capacity Plan submittal in which the EE Resource is initially committed
- Submit Updated M&V Plan no later than 30 days prior to next FRR Capacity Plan submittal in which EE Resource is subsequently committed
- Establish credit with PJM Credit Department prior to FRR Capacity Plan submittal (for planned EE Resources)
- Submit Energy Efficiency Resource Modification (EE MOD) in eRPM system
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed
- Submit Updated Post-Installation M&V Reports no later than business 15 days prior to each subsequent Delivery Year that the EE Resource is committed
- Permit Post- Installation M&V Audit(s) by PJM or Independent Third Party.

PJM Manual 18B: Energy Efficiency Measurement & Verification establishes the requirements for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports, and the M&V Audit.

11.5.1 Energy Efficiency Modifications (EE MODs)

RPM Business Rules for EE MODs in Section 4 of this manual apply to the FRR Alternative.

EE MODs must be in a "Provisionally Approved" or "Approved" status in order for the EE MOD to be considered in a party's EE Resource Position and in the calculation of Available ICAP to commit to the FRR Capacity Plan.

An EE MOD may be required prior to the Delivery Year to reflect the final Nominated EE Value of an EE Resource for the Delivery Year. An EE MOD decrease may result in the reduction of FRR Capacity Plan Commitments.

11.6 Locational Constraints in the FRR Alternative

As discussed in Section 2 locational constraints may require modeling constrained Locational Deliverability Areas (LDAs) separately. Locational Constraints are used to define the minimum Percentage of Internal Resources Required for a constrained LDA in the FRR Capacity Plan.

The constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year will be posted on the PJM website by February 1 prior to the commencement of the Base Residual Auction for that Delivery Year.

An LDA has a limited import capability to import resources from outside the LDA. In RPM these imported resources are considered in clearing the auction in an LDA and the auction results would reflect the effect of the imports in reducing the LDA clearing price. Similar to RPM Entities, FRR Entities are provided the benefit of import capability by allowing them to include some resources from outside the LDA in their Capacity Plan. The minimum Percentage of Internal Resources Required in a constrained LDA for the Delivery Year will be posted by February 1 prior to the commencement of the RPM Base Residual Auction for such Delivery Year. This Percentage of Internal Resources Required in an LDA is used to determine the Amount of Internal Resources Required (UCAP MWs) by the FRR LSE in the LDA. An approved Qualified Transmission Upgrade may be used to reduce the Amount of Internal Capacity Required in the LDA for the FRR LSE. An LSE must include enough capacity resource in its FRR Capacity Plan to satisfy the Amount of Internal Resources Required in the LDA. These capacity resources must be physically located in the LDA in which the FRR Service Area is located in order to satisfy this requirement.

The LDA Reliability Requirement is the projected internal capacity in the LDA plus the Capacity Emergency Transfer Objective (CETO) for the Delivery Year, as determined by the RTEP process. The internal resource requirement in an LDA is the LDA Reliability Requirement less the Capacity Emergency Transfer Limit (CETL) for the Delivery Year, as determined by the RTEP process. This internal resource requirement is expressed as a percentage of the Unforced Capacity Obligation based on Preliminary LDA/Zonal Peak Load Forecast multiplied by FPR to determine the Amount of Internal Resources (UCAP MWs) Required by the FRR LSE in the LDA.

Capacity Transfer Rights (CTRs) are implicitly allocated to the FRR LSE in the determination of the Percentage of Internal Resources Required in an LDA. An FRR LSE will not be eligible for any explicit CTRs.

11.7 Conditions on Sales by FRR Entities

If an FRR LSE has not satisfied a Threshold Quantity, they may not offer to sell capacity in excess of the amount needed to satisfy Preliminary/Final Daily Unforced Capacity Obligation bilaterally into RPM or in RPM Auctions; however, they may offer to sell such excess capacity to an External Party (i.e., delist) or to an FRR Entity. If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the amount needed to satisfy their Threshold Quantity bilaterally into RPM or in RPM Auctions up to a Sales Cap Amount. The Sales Cap and other rules related to sales by FRR Entities are shown below:

- The Sales Cap Amount is equal to the lesser of (a) [(0.25 * Preliminary Unforced Capacity Obligation or (b) 1300 MW.

- If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the Preliminary/Final Daily Unforced Capacity Obligation to an External Party (i.e., delist) or to another FRR Entity. In order for this type of sale to proceed, the Seller's FRR Capacity Commitments on the unit must be reduced.
- Sell offers in RPM Auctions and bilateral unit-specific transactions will be subject to offer and bilateral transaction checks to ensure that the seller does not violate any "Conditions on Sales by FRR Entities".
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" will be rejected.

If an FRR LSE serves load under the FRR Alternative and additional load under the RPM, the LSE may self-supply capacity resources in RPM Auctions and avoid the requirement to satisfy a Threshold Quantity; however, the MW amount of their sell offer(s) may not exceed a Self-Supply Offer Cap Amount.

- The Self-Supply Offer Cap Amount is the lesser of (a) 0.25 * (FRR Preliminary Daily Unforced Capacity Obligation + RPM Expected UCAP Obligation) or (b) 200 MW.
- An LSE's RPM Expected UCAP Obligation in a Zone is equal to the LSE's allocation of the Zonal Weather Normalized Summer Peak for summer four years prior to the Delivery Year (i.e., an Obligation Peak Load) * (Preliminary Zonal Peak Load Forecast/Zonal Weather Normalized Summer Peak for summer four years prior to Delivery Year) * Forecast Pool Requirement.

11.8 Delivery Year Activity

11.8.1 Final Daily Unforced Capacity Obligation

The Final Daily Unforced Capacity Obligation of an LSE in a zone equals the LSE's Final Obligation Peak Load in the zone * the Final Zonal FRR Scaling Factor * the Forecast Pool Requirement. The Forecast Pool Requirement updated for the RPM Third Incremental Auction will be used in determining the Final Daily Unforced Capacity Obligation.

The Final Daily Unforced Obligation shall be reduced by the committed Nominal PRD Value associated with such load that was approved by PJM in advance of the BRA and Third IA for such Delivery Year, multiplied by final Forecast Pool Requirement for the Delivery Year.

A reduction in the Daily Unforced Capacity Obligation is applicable in the case of annexation of service territory where the FRR load is acquired by a party that has not elected FRR alternative.

11.9 Deficiency Charges & Penalties

11.9.1 FRR Capacity Resource Deficiency Charges

An LSE participating in the FRR Capacity Plan Alternative will pay a FRR Capacity Resource Deficiency Charge in the delivery year for any shortage of resources to meet the Final Daily Unforced Capacity Obligation and the Amount of Internal Resources Required in an LDA.

A shortage/excess of resources to meet the Amount of Internal Resources Required in an LDA is calculated by comparing an LSE's Daily LDA FRR Resource Position to the Amount of Internal Resources Required in an LDA. If the Daily LDA FRR Resource Position is less than the Amount of Internal Resources Required in an LDA, a FRR Capacity Resource Deficiency Charge for this shortage will be assessed.

A shortage/excess of resources to meet the Final Daily Unforced Capacity Obligation is calculated by comparing an LSE's Daily Total FRR Resource Position to their Final Daily Unforced Capacity Obligation. If the Daily Total FRR Resource Position is less than Final Daily Unforced Capacity Obligation, a deficiency charge for this shortage less the shortage calculated for failure to satisfy the Amount of Internal Resources Required in the LDA will be assessed.

Shortages in meeting the Minimum Annual Resource Requirement in an LDA and the Minimum Extended Summer Resource Requirement in an LDA are calculated separately.

A shortage of Annual Resources to meet the Final Daily Minimum Annual Resource Requirement in an LDA is calculated by comparing the total Annual Resources in an LDA that comprise the LSE's Daily Total FRR Resource Position to their Final Daily Minimum Annual Resource Requirement in an LDA. If the total amount of Annual Resources in an LDA that comprise the Daily Total FRR Resource Position is less than Final Daily Minimum Annual Resource Requirement in an LDA, a deficiency charge for this shortage will be assessed (starting with the 2014/2015 Delivery Year).

A shortage of in the total amount of Annual Resources and Extended Summer Demand Resources in an LDA to meet the Final Daily Minimum Extended Summer Resource Requirement in an LDA is calculated by comparing the total Annual Resources and Extended Summer Demand Resources in an LDA that comprise the LSE's Daily Total FRR Resource Position to their Final Daily Minimum Extended Summer Resource Requirement in an LDA. If the total amount of Annual Resources and Extended Summer Demand Resources that comprise the Daily Total FRR Resource Position is less than Final Daily Minimum Extended Summer Resource Requirement in an LDA, a deficiency charge for this shortage will be assessed (starting with the 2014/2015 Delivery Year).

The FRR Capacity Resource Deficiency Charge is equal to 1.2 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such zone, weight-averaged for the Delivery Year based on the prices established and the quantities cleared in such auctions, multiplied by the shortage.

FRR Capacity Resource Deficiency Charges are assessed daily and billed monthly.

11.9.2 Transmission Upgrade Delay

If a Qualifying Transmission Upgrade is not completed by the start of the Delivery Year and the upgrade was not replaced with an equivalent amount of Capacity Resources in the LDA into which the import capability was to be increased, then the Amount of Internal Capacity Resources Required in an LDA will be increased and the LSE may be assessed a FRR Capacity Resource Deficiency Charge.

11.9.3 Peak-Hour Period Availability Charge

All generation resources that have FRR Capacity Plan Commitments are subject to the Generating Unit Peak Period Availability Measure.

RPM Business Rules regarding the Generation Unit Peak Period Availability Measure and Peak-Hour Availability Charge in Section 8 of this manual apply to the FRR Alternative.

11.9.4 Generation Resource Rating Test Failure Charge

All generation resources that have FRR Capacity Plan Commitments are subject to Capacity Testing for both the Summer and Winter Periods.

RPM Business Rules regarding the Capacity Testing and Generation Resource Rating Test Failure Charges apply to the FRR Alternative. Peak Season Maintenance Compliance Penalty Charge.

11.9.5 Peak Season Maintenance Compliance Penalty Charge

All generation resources that have FRR Capacity Plan Commitments are subject to Peak Season Maintenance Compliance.

RPM Business Rules regarding the Peak Season Maintenance Compliance Penalty Charges apply to the FRR Alternative.

11.9.6 Load Management Event Compliance Penalties

LSEs that have committed Demand Resources to their FRR Capacity Plan are subject to a compliance check performed after each PJM-initiated Load Management event that occurs during the months June through September.

Please refer to Section 8 of this manual for details on Load Management Event Compliance.

11.9.7 Load Management Test Compliance

DR Resource providers are required to simultaneously test all of their committed DR resources in a zone if no PJM-initiated load management event is called by PJM during the Delivery Year.

Please see Section 8 of this manual for details on Load Management Test Compliance.

11.10 Allocation of Deficiency Charges

The Daily FRR Capacity Resource Deficiency Charges, FRR Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, and Peak Season Maintenance Compliance Penalty Charges, and Load Management Test Failure Charges are distributed on a pro-rata basis to the LSEs in the RTO that were charged an RPM Locational Reliability Charge.

Daily Capacity Resource Deficiency Charges, Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, and Peak Season Maintenance Compliance Penalty Charges, and Load Management Test Failure Charges are allocated on a pro-rata basis to RPM LSEs based on their daily unforced capacity obligation.

11.11 Auction Specific MW Transactions

11.11.1 Auction Specific MW Transactions

LSEs that elect the FRR Alternative may report Auction Specific MW Transactions if they have cleared capacity in RPM Auctions through the eRPM system.

Approved Auction Specific MW Transactions do not contribute to the Sales Cap Amount for RPM Auctions described in the FRR Business Rules.

Attachment A: Glossary of Terms

Welcome to the *Glossary of Terms* section of the PJM Manual for the *Capacity Market*. In this section, you will find the following information:

Active Load Management (ALM) – prior to the implementation of RPM, the term that referred to end-use customer load which can be interrupted at the request of PJM.

Adjusted Zonal Capacity Prices – are the results of the Second Incremental Auction. Preliminary Zonal Capacity Prices that result from the Base Residual Auction are adjusted to account for the procurement in the 2nd Incremental Auction for the RTO.

Auction Specific MW Transactions – are transactions reported to PJM via eRPM between a buyer and seller that report the transfer of physical MW between the buyer and seller using the eRPM system and PJM settlement process. Auction Specific MW Transactions are not eligible to be offered in an RPM auction Auction Specific MW Transactions are settled at the weighted average Resource Clearing Price of the MW supplying the transaction.

Available Transfer Capability (ATC) -- is the amount of energy above "base case" conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM Control Area under specified system conditions.

Base LDA Unforced Capacity Obligation – is equal to the sum of the Base Zonal Unforced Capacity Obligations for all the zones in an LDA and is the result of the clearing of the Base Residual Auction.

Base Offer Segment -- is the sell offer segment that may be offered as either a single price quantity for the capacity of the resource or divided into up to ten (10) offer blocks with varying price-quantity pairs that represent various output levels of the resource. The Base Offer Segment will consist of block segments at the specified price-quantity pairs.

Base Residual Auction (BRA) -- allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

Base RTO Unforced Capacity Obligation -- determined after the clearing of the BRA and is posted with the BRA results. The Base RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the BRA plus the Forecast RTO Interruptible Load for Reliability (ILR) Obligation.

Base Unforced Capacity Imported into an LDA – is equal to the Base LDA Unforced Capacity Obligation less the LDAs Unforced Capacity cleared in the Base Residual Auction less the LDA Short-Term Resource Procurement Target Allocation. This value is used to determine the maximum total amount of Capacity Transfer Rights that are allocated into an LDA in the Base Residual Auction for the Delivery Year.

Base Zonal RPM Scaling Factor – is determined for each zone and is equal to the [(Preliminary Zonal Peak Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Years) * ((RTO Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO

Preliminary Peak Load Forecast * the Forecast Pool Requirement))]. Base Zonal RPM Scaling Factors are posted with the Base Residual Auction results.

Base Zonal Unforced Capacity Obligation – determined for each zone and is equal to the (Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement) + Short Term Resource Procurement Target. Base Zonal Unforced Capacity Obligations are posted with the Base Residual Auction clearing results.

Behind the Meter Generation – a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of Interconnection. Behind the Meter Generation may not include at any time any portion of a generating unit's capacity that is designated as a Capacity Resource or any portion of the output of a generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market at any time.

Bilateral Market – provides LSEs the opportunity to hedge the Locational Reliability Charge determined through the BRA and Second Incremental Auction. The bilateral market also provides resource providers an opportunity to cover any auction commitment shortages.

Bilateral Unit-Specific Transaction – transaction that enables reporting of the transfer of ownership of a specified amount of installed capacity from a specific unit from one party to another.

Capacity Modification (Cap Mod) – transaction that enables generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in eRPM, or the request an MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

Capacity Resources – includes megawatts of net capacity from existing or planned generation capacity resources or load reduction capability provided by Demand Resources or ILR in the PJM Region.

Capacity Emergency Transfer Limit (CETL) – the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Objective (CETO) – the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency.

Capacity Transfer Rights (CTR) – rights used to allocate the economic value of transmission import capability that exists into a constrained LDA. Serve to offset a portion of the Locational Price Adder charged to load in constrained LDAs.

Control Area – electric power system or combination of electric power systems bounded by interconnection metering and telemetering to which a common generation control scheme is applied in order to:

(a) Match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s) with the load within the electric power system(s)

(b) Maintain scheduled interchange with other Control Areas

(c) Maintain the frequency of the electric power system(s)

(d) Maintain power flows on transmission facilities within appropriate limits to preserve reliability

(e) Provide sufficient generating capacity to maintain operating reserves.

Cost of New Entry (CONE) – Levelized annual cost in ICAP $/MW-Day of a reference combustion turbine to be built in a specific location.

CTR Settlement Rate – The CTR Settlement Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of the Base Residual Auction and Second Incremental Auction divided by the Total CTR MWs allocated to LSEs in the zone.

Daily Unforced Capacity Obligation - of equals the LSE's Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement for an LSE in a zone/area.

Daily Capacity Resource Deficiency Charge – assessed to party when the Daily RPM Resource Position of its resource is less than the Daily RPM Resource Commitment for such resource on a delivery day. This charge is applicable to generation resource, Demand Resource, or Qualified Transmission Upgrade.

Delivery Year – Planning period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012 – May 31, 2013 Planning Period.

Demand Resource – a resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.

Demand Resource Factor (DR Factor) – used to determine the reliability benefit of demand resource products and to assign an appropriate value to demand resource products. The DR Factor is calculated by PJM and is approved and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year.

Demand Resource Modification (DR Mods) -- transaction used by PJM to track an increase or decrease of the nominated value of the Demand Resource in a party's resource portfolio in eRPM.

Electric Cooperative – an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distribution Company (EDC) – PJM Member that owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Control Area.

Emergency – an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scare fuel; or a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End Use Customer – a member that is a retail end-user of electricity within the PJM region.

Equivalent Demand Forced Outage Rate (EFORd) – is a measure of the probability that generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate. See Generator Resource Performance Indices Manual (M-22) for equation.

Equivalent Demand Forced Outage Rate (EFORd-5) – is EFORd determined based on five years of outage data through September 30 prior to the Delivery Year. This is an index similar to EFORd that is the basis for a unit's UCAP value for the Delivery Year, and it does not include the events that are outside management control (OMC events). The index is calculated using Generator Availability Data System (GADS) data in PJM. If a generating unit does not have a full 5 years of history, the EFORd-5 will be calculated using class average EFORd and the available history as described in Reliability Assurance Agreement, Schedule 5, Section C. The class average EFORd will be used for a new generating unit. The class average EFORds that are used by PJM to calculate a unit's EFORd-5 are posted to the PJM website by November 30 prior to the Delivery Year.

Effective EFORd – the most recently calculated EFORd that has been bridged to the eRPM system. During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year. This is the basis for a unit's UCAP value, and it does not include the events that are outside management control (OMC events).

Facilities Study Agreement (FSA) – is the agreement that must be executed by a Generation and/or Transmission Interconnection Customer to authorize PJM to proceed with an Interconnection Facilities Study. Refer to PJM OATT section 36.6 for Generation Interconnection projects and OATT section 41.5 for Transmission Interconnection projects.

FERC – Federal Energy Regulatory Commission or any successor federal agency, commission or department.

Final RTO Unforced Capacity Obligation –The Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year. The RTO unforced capacity obligation through all RPM Auctions is equal to the total MWS cleared in PJM Buy Bids in RPM Auctions less the total MWs cleared in PJM Sell Offers in RPM Auctions.

Final Zonal Capacity Prices – are the capacity prices assessed to RPM Load Serving Entities through the RPM Locational Reliability Charge. The Final Zonal Capacity Prices are determined by PJM after the Third Incremental Auction. Final Zonal Capacity Prices reflect the final price adjustments that may be necessary to account for any granted requests for relief from Capacity Resource Deficiency Charges due to permanent departure of load.

Final Zonal RPM Scaling Factors – used in determining an LSE's Daily Unforced Capacity Obligation. A Final Zonal RPM Scaling Factor for a zone is equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Peak for the summer prior to the Delivery Year). The Final Zonal RPM Scaling Factors are posted two weeks following the final Incremental Auction.

Final Zonal Unforced Capacity Obligation – The Final Zonal Unforced Capacity Obligation is equal to the zonal allocation of the Final RTO Unforced Capacity Obligation and is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load

Forecasts. The Final Zonal UCAP Obligations are determined after the clearing of the final Incremental Auction for the Delivery Year.

Firm Transmission Service – transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement (FRR) – an alternative method for a Party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

Flexible Self-Scheduled Resources – are resources specified by an LSE in the Base Residual Auction to provide a mechanism to manage quantity uncertainty related to the Variable Resource Requirement. For each resource-specific sell offer, the LSE must designate a flexible self-scheduling flag as well as an offer price that will be utilized in the market clearing in the event the resource is not needed to cover a specified percentage of the LSE's capacity obligation. Flexible self-scheduled resources will automatically clear the auction if they are needed to supply the LSE's resulting capacity obligation.

Forecast Pool Requirement (FPR) – the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region.

FRR Capacity Plan – a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR alternative.

FRR Service Area – the service territory of an IOU as recognized by state law, rule, or order; the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to and regularly reported to the Office of Interconnection or an EDC who agrees to aggregate the meters' load data for the FRR Service Area and regularly report the information to the Office of Interconnection or for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within the area excluding the load of Single-Customer LSEs that are FRR Entities. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Areas is defined as all customers physically connected to transmission or distribution facilities of the Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Requirements Service – wholesale service to supply all of the power needs of a LSE to serve end-users within the PJM Region that are not satisfied by its own generation facilities.

Generation Capacity Resource – a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of the Reliability Assurance Agreement. A generation resource may be an existing or planned Generation Resource.

Generation Owner – a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region.

Purchasing all or a portion of the output of a generation facility is not sufficient to qualify a Member as a Generation Owner.

Generator Forced Outage – an immediate reduction in output or capacity or removal from service 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 does not constitute a Generator Forced Outage.

Generator Maintenance Outage – the scheduled removal from service of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage.

Generator Planned Outage – the scheduled removal from service of a generating unit for inspection, maintenance or repair with the approval of the office of the Interconnection.

Incremental Auctions – Allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.

Incremental Capacity Transfer Rights – allocated to transmission expansion projects associated with new generation interconnection that were required to meet PJM Deliverability requirements and to Merchant Transmission Expansion projects and are applicable to all such projects that have gone through the PJM interconnection process since the beginning of the PJM RTEPP in 1999. Such incremental Capacity Transfer Rights allocation is based on the incremental increase in import capability across a Locational Constraint that is caused by the transmission facility upgrade. Incremental capacity transfer rights associated with Incremental Rights-Eligible Required Transmission Enhancements are allocated. Incremental Rights-Eligible Required Transmission Enhancements may include Regional Facilities and Necessary Lower Voltage Facilities, and Lower Voltage Facilities.

Installed Capacity (ICAP) – value based on the summer net dependable rating of the unit as determined in accordance with PJM's Rules and Procedures of the Determination of Generating Capacity.

Installed Reserve Margin (IRM) – used to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. The IRM is determined by PJM in accordance with the PJM Reserve Requirements Manual (M-20). The IRM is approved and posted prior to its use in an RPM Auction for the Delivery Year.

Interconnection Service Agreement (ISA) – an agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection.

Investor Owned Utility (IOU) – an entity with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Load Management – is the ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

Load Serving Entity (LSE) – any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer that (a) serves end-users within the PJM Control Area, and (b) is granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Control Area.

Locational Constraints – localized capacity import capability limitations that are caused by transmission facility limitations, voltage limitations or stability limitations that are identified for a Delivery Year in the PJM Regional Transmission Expansion Planning Process (RTEPP) prior to each Base Residual Auction. Such Locational Constraints are included in the RPM to recognize and to quantify the locational value of capacity.

Locational Deliverability Area (LDA) – sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Locational Price Adder – an addition to the marginal value of unforced capacity within an LDA as necessary to reflect the price of resources required to relieve the applicable binding locational constraints.

Locational Reliability Charge – Fee applied to each LSE that serves load in PJM during the delivery year. Equal to the LSEs Daily Unforced Capacity Obligation multiplied by the applicable Final Zonal Capacity Price.

Nested LDAs – when an aggregate of Zones, a Zone and its sub-zones are constrained LDAs, the LDAs are referred to as "Nested". When LDAs are nested, the Zonal CTR calculations include allocation of CTRs from RTO to aggregate of Zones as well as CTRs from aggregate of Zones to the Zone.

Net Energy & Ancillary Services (E&AS) Offset – is used to offset the value of Cost of New Entry (CONE) to determine the net value of CONE. This value is calculated using the historical averages of Energy &Ancillary Services revenue data for a reference combustion turbine. The E&AS Offset is calculated using a historical average of the three most recent calendar years.

New Entry Pricing – is an incentive provided to a Planned Generation Resource where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are capped. This allows Planned Generation Resources to recover the amount of its cost of entry-based offer for up to two additional consecutive years, under certain conditions, and to set the clearing price of all resources within that LDA for all three years.

Nominated DR Value – the nominated value of a Demand Resource is the value of the maximum load reduction and the process to determine this value is consistent with the process for the determination of the capacity obligation for the customer. Therefore, the maximum load reduction for each resource is adjusted to include system losses.

Non-Retail Behind the Meter Generation – Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Zone Load – the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

Obligation Peak Load – the summation of the weather normalized coincident summer peaks for the previous summer of the end-users for which the Party was responsible on that billing day.

Office of the Interconnection – the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM board.

Partial Requirements Service – wholesale service to supply a specified portion, but not all, of the power needs of a LSE to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Peak Period Capacity Available (PCAP) – Total Unit ICAP Commitment Amount of the generating unit times (1.0 – EFORp).

Peak-Period Equivalent Forced Outage Rate Peak (EFORp) – is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate during seasonal peak periods. Currently there are two sets of seasonal peak periods. The Summer peak period is defined as June through August non-holiday weekdays from 1400 to 1900. The Winter peak period is defined as January through February non-holiday weekdays from 0700 to 0900 and 1800 to 2000.

Percentage Internal Resources Required – for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with physically Capacity Resources located in that LDA.

Planned Demand Resource – a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing a reduction or control on or before the start of the Delivery Year for which the resource is to be committed.

Planned Generation Capacity Resource – a Generation Capacity Resource participating in the generation interconnection process for which Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which the resource is to be committed. A Facilities Study Agreement (FSA) must be executed prior to the BRA for the corresponding Delivery Year and an Interconnection Service Agreement (ISA) must be executed prior to any Incremental Auctions for the corresponding Delivery Year.

Planning Year – Annual period from June 1 to May 31 (also may be referred to as Planning Period).

Pool-Wide Average EFORd – average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all units that are planned to be in service during the delivery year. Determined by PJM and is approved and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. The OMC events are not considered in the EFORd values used to calculate Pool-Wide Average EFORd (this change as a part of RAA was filed with FERC on June 19).

Public Power Entity – any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the above, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrade (QTU) – a proposed enhancement or addition to the Transmission System that will increase the Capacity Emergency Transfer Limit (CETL) into an LDA by a megawatt quantity certified by PJM. A Qualified Transmission Upgrade is scheduled to be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction. Prior to the conduct of the Base Residual Auction for such Delivery Year, a Facilities Study Agreement (FSA) must be executed.

Regional Transmission Expansion Planning Process (RTEPP) – is PJM's comprehensive annual process that examines the three interrelated components of electric power system reliability: load, generation, and transmission. The RTEP Process employs a range of planning study tools and methodologies to analyze and assess each component to ensure that reliability remains firm. The RTEP Process is designed to meet established reliability criteria, keep markets robust and competitive, and ensure stable operations.

Regional Transmission Owner (RTO) – Each entity that owns, leases, or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce or that provides Transmission that is a party to the PJM Transmission Owners Agreement and PJM Operating Agreement

Reliability Pricing Model (RPM) – is PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Resource Clearing Price – is the clearing price in the Base Residual Auction or Incremental Auctions as determined by optimization algorithm for each auction. The Resource Clearing Price within an LDA is equal to the sum of (1) the marginal value of system capacity; and (2) the Locational Price Adder, if any, for the LDA; and (3) the Annual Resource Price Adder, if any, for the LDA; and (4) the Extended Summer Resource Price Adder, if any, for the LDA. The Resource Clearing Price for the Unconstrained Market Area is the marginal value of system capacity. PJM posts the Resource Clearing Prices for all resources that clear in the Base Residual Auction and all Buy Bids and Sell Offers that clear in the Incremental Auctions.

RTO Unforced Capacity Obligation – established in the BRA and is used to determine the Base Zonal RPM Scaling Factors to use in determining Base Zonal Unforced Capacity Obligation.

RTO Weather Normalized Summer Peak – the sum of the Zonal Weather Normalized Summer Coincident Peaks.

Self-Scheduled Resources – are resources specified by a resource provider in the Base Residual Auction to provide a mechanism to guarantee that the resource will clear in the Base Residual Auction. For each resource-specific sell offer, if a resource is designated as self-scheduled by the resource provider, the minimum and maximum MW amounts specified *must be equal and the sell offer price will be set to zero.* Self-Scheduled resources will be cleared first in the Base Residual Auction, and cannot set the clearing price as the marginal resource, since these resources lack flexibility.

Steady State Period – period of time where the auction schedule follows the proposed three year forward planning dates. The steady-state condition of RPM begins with the 2011/12 Delivery Year.

Target Unforced Capacity (TCAP) – the "target" to measure the peak period availability of capacity from the generator in the Delivery Year and it may be different from the Delivery Year UCAP value of such generator. The TCAP for a unit is calculated as the Total Unit ICAP Commitment Amount times (1 – EFORd-5).

Transmission Facilities – facilities within the PJM Region that have been approved by or meet the definition of transmission facilities established by FERC; or have been demonstrated to the satisfaction of the Office of Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner – a Member that owns or leases, with rights equivalent to ownership, Transmission Facilities. Taking transmission service is not sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity (UCAP) – installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Variable Resource Requirement Curve (VRR) – defines the maximum price for a given level of Capacity Resource commitment relative to the applicable reliability requirement. VRR Curves are defined for the PJM Region and each of the constrained LDAs within the PJM region.

Weighted Average Resource Clearing Price – the average of the Resource Clearing Prices that result in all the auctions for a specific Capacity Resource, weighted by the Unforced Capacity cleared for that particular resource. This value is used to determine the Daily Peak-Hour Period Availability Charge Rate for an individual resource.

Weighted Zonal Resource Clearing Price – the average of the Resource Clearing Price of the sub-zones, weighted by the Unforced Capacity of Resources Cleared in each of the sub-zones. This is also used to calculate the Auction Credit to DR on the zonal basis if EDC cannot provide DR data by sub-zones.

Zonal Capacity Price – the price of *UCAP in a Zone that an LSE that has not elected the* FRR Alternative is obligated to pay for a Delivery Year. Zonal capacity prices are calculated as a result of the clearing of all RPM Auctions for the Delivery Year. A zonal capacity price consists of the following price components: (1) the marginal value of system capacity for the PJM Region; (2) the Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA); (3) an adjustment in the Zone, if required, to account for any resource make-whole payments; and (4) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer DR. *Preliminary Zonal Capacity Prices* are the result of the clearing of the Base Residual Auction. *Adjusted Zonal Capacity Prices* are the result of the clearing of the Base Residual Auction and any Incremental

Auction(s). *Final Zonal Capacity Prices* are determined after the Final Incremental Auction for the Delivery Year.

Zonal CTR Credit Rate (Base and Final) – the rate calculated as a ratio of economic value of CTRs to zonal unforced capacity obligation. These rates are calculated as the Base Zonal CTR Credit Rate after the Base Residual Auction and as the Final CTR Credit Rate adjusted for the results of all RPM Auctions. Zonal CTR Credit Rate is subtracted from Zonal Capacity Price to estimate Net Load Price.

Zonal CTR Settlement Rate – a rate calculated as a ratio of economic value of CTRs to total CTRs allocated to LSEs in a zone. This rate is used to settle CTRs by calculating credit for CTRs owned.

Zone -- an area within the PJM Region or such areas that may be combined as a result of mergers and acquisitions; or added as a result of the expansion of the boundaries of the PJM Region. A Zone will include any Non-Zone Network Load located outside the PJM Region that is served from inside a particular Zone.

Attachment B: Authorization to Self-Schedule Capacity

AUTHORIZATION TO SELF-SCHEDULE CAPACITY

This Authorization to Self-Schedule Capacity ("Authorization") of _________________ ("Owner"), effective this ___ day of ____, 20___, hereby authorizes PJM Interconnection, L.L.C. ("PJM") to self-schedule on its behalf capacity associated with a specific generating unit ______________________ ("Unit"), which it will own or control for a portion of the delivery year from June 1 to May 31, 20___ to 20___ ("Delivery Year"), with the following other party or parties owning or controlling the Unit for the balance of such delivery year (if known): ____ ("Other Owners"). Owner states that it will own or control the Unit during the period(s) within the Delivery Year from ___/___/___ to ___/___/___ and any additional periods listed hereafter: ____.

RECITALS:

WHEREAS, PJM Interconnection, L.L.C. ("PJM") is a Regional Transmission Organization ("RTO") that administers the Reliability Pricing Model ("RPM"), a centralized market for obtaining the electric capacity resources necessary to ensure resource adequacy in its control area;

WHEREAS, a capacity resource must remain available for the entire delivery year in order to be eligible to offer its capacity in RPM auctions;

WHEREAS, an owner may seek to sell capacity in an RPM auction associated with a generating unit that such owner owns or controls for only a portion of the delivery year as result of a transaction specific to such unit commencing or terminating within a delivery year;

WHEREAS, PJM, in order to facilitate participation in its auctions of all capacity resources potentially available, permits owners collectively to authorize PJM to self-schedule the Unit on their behalf capacity owned or controlled by such owner for a portion of the delivery year,

AUTHORIZATION

NOW, THEREFORE, Owner authorizes PJM to self-schedule its Unit during the years during which it will own or control the Unit for only a portion of the identified delivery year(s), and acknowledges that it understands and accepts the following terms and conditions of this authorization:

1. Each Owner and Other Owner (i) must submit to the PJM-designated electronic mail address a fully prepared and executed Authorization from the Owner and each Other Owner at least 5 business days prior to the opening of the bidding window of an RPM auction and (ii) must submit as the "seller" into the eRPM electronic interface system a new unit-specific transaction(s) indicating "Self Scheduling Coordinator (SELFSC)" as the "buyer" prior to the opening of the auction bidding window. Owner understands that failure of any Other Owner to satisfy both of these requirements shall preclude a Unit from participation in an RPM auction even where Owner otherwise has otherwise fully complied.

2. Because PJM will use the Unit's current $EFOR_d$ rating in the self-schedule, Owner recognizes that, consequently, the Unit's unforced capacity value may change between the time the Unit is offered into the RPM Auction and the delivery year for which the Unit was self-scheduled.

3. Because PJM will self-schedule the Unit, Owner recognizes that the Unit's offer will always clear an auction and that Owner must accept the applicable clearing price.

4. PJM automatically will transfer to Owner (and each Other Owner) the cleared capacity of the Unit for the portion of the Delivery Year during which it owns or controls the Unit, and that, as the "buyer" in this unit specific transaction, the Owner will for the duration of this period be responsible for any Capacity Resources Deficiency Charges that may be assessed (including those resulting from a reduced $EFOR_d$ rating), and, for the duration of the delivery year, its proportional share of any Peak-Hour Period Availability Charges, Generation Test Resource Rating Test Failure Charges, or Peak Season Maintenance Compliance Penalty Charges that may be assessed under RPM rules.

The undersigned, having been granted eRPM Read/Write Access by Owner and duly authorized to act on Owner's behalf, declares to PJM the authority described here above and intends that PJM may rely upon such declaration even to Owner's detriment.

Signed this ____th day of _______________, 20____

____

Signed by: ____________________
Title: ____________________

Attachment C: Demand Resource Sell Offer Plan

The Demand Resource Sell Offer Plan (DR Sell Offer Plan) is a PJM template document, requiring the information set forth below, together with an accompanying signed PJM Demand Resource Officer Certification Form (DR Officer Certification Form). A completed DR Sell Offer Plan (including a signed DR Officer Certification Form) must be submitted to PJM no later than 15 business days prior to the relevant RPM Auction by Curtailment Service Providers (CSPs) that intend to offer Demand Resources (DR) in RPM Auctions. The DR Sell Offer Plan must provide information that supports the CSP's intended DR Sell Offers and demonstrates that the DR is being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through DR registrations for the relevant Delivery Year.

The DR Sell Offer Plan encompasses both existing DR and Planned DR. Existing DR is identified as end-use customer sites that the CSP has under contract for the current Delivery Year (i.e. end-use customer sites registered in the PJM eLRS system for the current Delivery Year)[12] and that the CSP intends to have under contract for the auction Delivery Year. Planned DR is that quantity of the CSP's intended total DR Sell Offer in excess of the CSP's existing DR and is subject to an RPM Credit Requirement.

Both the signed DR Officer Certification Form and the completed DR Sell Offer template must be submitted to PJM via email to rpm_hotline@pjm.com no later than 15 business days prior to the relevant RPM auction. PJM will review the DR Sell Offer Plan and notify the CSP via email no later than 10 business days prior to the RPM Auction if another CSP has identified the same end-use customer site(s) in their DR Sell Offer Plan and request supporting documentation, such as a letter of support from the end-use customer indicating that the end-use customer and CSP are likely to execute a contract for the auction Delivery Year. Supporting documentation must be submitted via email to the rpm_hotline@pjm.com no later than 7 business days prior to the RPM Auction. PJM will notify all CSPs via the eRPM system of the approved DR MW quantity by zone/sub-zone that the CSP is permitted to offer into the RPM Auction no later than 5 business days prior to the RPM Auction.

I. PJM Demand Resource Officer Certification Form

A DR Officer Certification Form is located in Attachment D of Manual 18 and is posted on the PJM web site. A signed DR Officer Certification Form must accompany the DR Sell Offer Plan. The DR Officer Certification Form specifies that the signing officer has reviewed the DR Sell Offer Plan, that the information provided therein is true and correct, and that the MW quantity that clears the auction is reasonably expected to be physically delivered through DR registrations for the relevant Delivery Year.

[12] For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM eLRS system for the subsequent Delivery Year may also be considered as existing DR provided the registrations are in "Confirmed" status by specified deadlines established by PJM and communicated to CSPs in advance of the DR Sell Offer Plan submittal deadline.

II. DR Sell Offer Plan Template

A DR Sell Offer Plan template (in Excel format) is provided on the PJM web site, and consists of the following three sections:

A. DR Sell Offer Plan Summary
B. Planned DR Details
C. Schedule

A. DR Sell Offer Plan Summary

The DR Sell Offer Plan requires the following information to be provided:

- Company name
- Contact information (name, phone number and email address of submitter)
- Existing Nominated DR Value in ICAP MWs by zone/subzone that CSP intends to offer
- Planned Nominated DR Value in ICAP MWs by zone/subzone that CSP intends to offer

Existing DR is identified by the CSP as end-use customer sites that the CSP has under contract and registered in the PJM eLRS System for the current Delivery Year and that the CSP also intends to have under contract for the auction Delivery Year. Planned DR is identified by the CSP as described in the Planned DR Details section of the DR Sell Offer Plan template. Based on the information provided above, a total Nominated DR Value in MWs will be calculated for each zone/sub-zone as the addition of the Nominated DR Value of existing DR plus the Nominated DR Value of Planned DR. The total Nominated DR Value represents the maximum MW amount that the CSP intends to offer for the zone/sub-zone. The actual MW value(s) submitted by a CSP in their Sell Offer(s) for a zone/sub-zone during the auction bidding window may be less than the total Nominated DR Value in their DR Sell Offer Plan Summary.

Certain zones/sub-zones will be pre-identified by PJM as zones for which DR Sell Offers may require additional information to support the plan. Additional information may be required to support DR Sell Offer Plans for zones/sub-zones for which the quantity of cleared zonal/sub-zonal DR from the last BRA exceeds a threshold determined for the applicable LDA group (EMAAC, SWMAAC, Rest of MAAC, or Rest of RTO) as the higher of the maximum DR/ILR quantity registered in eLRS over the past three Delivery Years for the zones in the LDA group or the zonal DR potential quantity for the zones in the LDA group estimated based on a June 2009 FERC Staff Report on "A National Assessment of Demand Response Potential", where DR quantities are expressed in all cases as a percent of the forecasted zonal peak load. This determination of the identified zones is made each year prior to each BRA and is applicable to all auctions conducted for that Delivery Year. Zones or sub-zones remain on the identified list unless the threshold is not exceeded for three consecutive years. Identified zones for a Delivery Year will be posted by PJM to the pjm website no later than December 1 prior to the Base Residual Auction for such Delivery Year. Updates, if any, made to the 2009 FERC Staff Report will be subject to stakeholder review and considered for use in the establishment of thresholds in the future.

For these pre-identified zones/sub-zones, a CSP sell offer threshold is determined for each CSP; and DR sell offer quantities in excess of the CSP sell offer threshold will require site-specific information, as this quantity in excess of the CSP sell offer threshold should reflect Planned DR associated with end-use customer sites that the CSP has a high degree of certainty that it will physically deliver for the Delivery Year. The CSP sell offer threshold is determined as the higher of [(the CSP's maximum DR quantity registered in eLRS for that zone/sub-zone over the past three Delivery Years) or (the CSP's maximum cleared DR quantity for the past three BRAs for that zone/sub-zone) or (10 MW)].

B. Planned DR Details

The Planned DR Details section describes the program or strategy for procuring end-use customers and provides the details and key assumptions behind the development of the Planned DR quantities contained in the CSP's DR Sell Offer Plan. The Planned DR Details section is comprised of three sub-sections.

1. Description and Key Assumptions of Planned DR

The CSP must describe the program(s) that the CSP plans to employ to achieve the Planned Nominated DR Value indicated on the DR Sell Offer Plan Summary. This section must describe key program attributes and assumptions used to develop the Planned Nominated DR Value. This section must include, but is not limited to, discussion of:

- Method(s) of achieving load reduction at customer site(s)
- Equipment to be controlled or installed at customer site(s), if any
- Plan and ability to acquire customers
- Types of customer targeted
- Support of market potential and market share for the target customer base, with adjustments for existing DR customers within this market and the potential for other CSPs targeting the same customers
- Assumptions regarding regulatory approval of program(s), if applicable
- If offering a Direct Load Control (DLC) program, the following additional DLC program details must be provided:
    - Description of the cycling control strategy
    - A list of all load research studies[13] (with study dates) used to develop the estimated nominated ICAP value (kW) per customer (i.e., the per-participant impact). A copy of all studies must be provided with the DR Sell Offer Plan. If the DLC program employs a radio signal, the CSP may elect to either submit a load research study to support the estimated nominated ICAP value per customer or utilize the per-participant impacts contained in the "Deemed Savings

[13] Direct Load Control Research Study Guidelines are provided in PJM Load Forecasting and Analysis Manual, Manual 19, Attachment B.

Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in the PJM Region" Report[14].

- Assumptions regarding switch operability rate (%)

2. Planned Nominated DR Value by Customer Segment

For those Planned Nominated DR Values for which an end-use customer site is not identified in section 3 of the Planned DR Details, the CSP must identify the Planned Nominated DR values by zone/sub-zone and by end-use customer segment. End-use customer segments include residential, commercial, small industrial (less than 3 MW), medium industrial (between 3 MW and 10 MW) and large industrial (greater than 10 MW). If known, the CSP may identify more specific customer segments within the commercial and industrial category.

By zone/sub-zone and by end-use customer segment, the CSP must provide estimates of the following information regarding the Planned DR component of the DR Sell Offer Plan:

- Number of end-use customers to be registered for auction Delivery Year
- Average Peak Load Contribution (PLC) per end-use customer in kW
- Average Nominated DR Value per customer in kW

Based on the above provided information, a total Planned Nominated DR Value in MW will be calculated for each end-use customer segment and for each zone/sub-zone. The total Planned Nominated DR values identified by customer segment and aggregated for each zone/sub-zone in Section 2 of the Planned DR Details plus the total Planned Nominated DR Values identified by end-use customer site(s) and aggregated for each zone/sub-zone in Section 3 of the Planned DR Details must equal the total Planned Nominated DR Value for each zone-sub-zone as identified in the DR Sell Offer Plan Summary.

3. Planned Nominated DR Value by End-Use Customer Site

This section must be completed by the CSP when the end-use customer is known at the time of the submittal of the DR Sell Offer Plan. This section must also be completed for DR Sell Offer quantities identified in the DR Sell Offer Plan Summary as requiring site-specific information, since this identified quantity should reflect Planned DR associated with specific end-use customer sites for which the CSP has a high degree of certainty that it will physically deliver for the relevant Delivery Year.

[14] "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in the PJM Region", Final Report, RLW Analytics, March 2007, is available at http://www.pjm.com/~/media/documents/reports/20070406-deemed-savings-report-ac-heat.ashx

The CSP must provide the following information:

- Customer EDC account number (if known)
- Customer name
- Customer premise address
- Zone/Sub-zone
- Customer segment
- Actual value (if known) or estimate of current PLC and estimate of expected auction Delivery Year PLC in kW
- Estimated Nominated DR Value in kW

In the event that multiple CSPs identify the same end-use customer site, the MWs associated with such site will not be approved for offering into the RPM auction by any of the CSPs, unless it can be supported by evidence, such as a letter of support from the end-use customer indicating that they have been in contact with the CSP and are likely to execute a contract with that CSP for the relevant Delivery Year. In the event that multiple letters of support indicating different CSPs are provided from the end use customer, the MWs associated with the end-use customer site will not be approved for offering into the RPM auction by any of the CSPs.

C. Schedule

The CSP must provide an approximate timeline for procuring end-use customer sites in order to physically deliver the total Nominated DR Value (existing and Planned DR) by zone/sub-zone in the DR Sell Offer Summary. For each zone/sub-zone and for each customer segment, the CSP must specify the cumulative number of customers and the cumulative Nominated DR Value associated with that group of customers that the CSP expects to have under contract by the beginning of each of the full Delivery Years occurring between the time of the auction and the auction Delivery Year.

Attachment D: Demand Resource Officer Certification Form

PJM DEMAND RESOURCE SELL OFFER PLAN
OFFICER CERTIFICATION FORM

Market Participant Name: ________________________________
("Participant")

I, ________________________________, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. ("PJM") and PJM Settlement, Inc. ("PJM Settlement") are relying on this certification as evidence that Participant meets all requirements for participating in PJM's Reliability Pricing Model ("RPM") auctions, as set forth in the PJM Open Access Transmission Tariff ("PJM Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"), and in the PJM Manuals, hereby certify that, as of the date of this certification, to my knowledge and belief:

1. I have reviewed Participant's Demand Resource Sell Offer Plan (the "Plan") and the information supplied to PJM in support of the Plan is true and correct as of the date of this certification.

2. The Participant is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of this certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

3. This certification does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Participant's rights and obligations thereunder, including Participant's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

Date: ____________________ By: ____________________________
(Signature)

Print Name: ______________________
Title: ____________________________

Revision History

Revision 17 (12/20/2012):

- Conforming revisions in Docket ER13-305-000 to add a Cleveland LDA (Section 2.3.1)
- Conforming revisions in Docket ER13-149-000 to incorporate task oriented deadlines to ensure timely submission of offer data, exception requests and unit-specific requests by market participants as well as timely responses thereto by PJM and the IMM
- Removal of language restricting replacement transactions on EE Resources with non-EE Resources (Section 8.7)
- Removal of ILR related content
- Removal of Transition Period (2007/08 – 2010/11 Delivery Year) related content
- Removal of pre-2012/13 Delivery Year-specific content
- Glossary updates

Revision 16 (09/27/2012):

- Conforming revisions for FERC Order ER11-4628 accepted on 12/14/2011 and effective 05/15/2012 to integrate Price Responsive Demand (PRD) in PJM Capacity Market.

Revision 15 (06/28/2012):

- Conforming revisions for FERC Order ER12-1372 accepted on 05/31/2012 and effective 06/01/2012, to clarify load management event and test compliance requirements related to sub-zonal and product-specific dispatch (Sections 4.3.1, 8.5, 8.5.2, 8.6, 9.1.7, and 9.1.9).
- Conforming revisions for FERC Order ER11-3322 conditionally accepted on 02/24/2012 and effective June 1, 2012, to implement a Demand Response Transition Provision (DR Capacity Transition Credit and Alternate DR Transition Credit) for the 2012/2013 through 2014/2015 Delivery Years (Sections 8.8 and 9.4).
- Conforming revisions for FERC Order ER12-513, accepted on 01/30/2012 and effective 01/31/2012, to revise point (a) on the VRR Curve (Section 3.4) and clarify New Entry Pricing provision (Section 5.3.3).
- Conforming revisions for FERC Order ER12-636, accepted on 02/16/2012, and effective 02/18/2012, to make corrections, clarifications identified as a result of the Quality Project Initiative including revisions for CTRs and ICTRs (Sections 5.8.3, 5.8.4, 6.1.1, 6.1.2, 6.1.3, 6.2, 6.3, 6.4, and 9.3.4) and removal of obsolete provisions for Single Customer LSE electing the FRR Alternative and the Unauthorized Load Transfer Charge (Section 11.2.3).
- Revisions to correct bill timing from monthly to weekly for Capacity Resource Deficiency Charges (Section 9.1.3), Locational Reliability Charges (Section 9.2.1),

Auction Charges/Credits (Sections 9.3.1 and 9.3.2), CTR and ICTR Credits (Section 9.3.4), Auction Specific MW Transaction Credits (Section 9.3.5), and ILR Credits (Section 9.3.6).

Revision 14 (02/23/2012):

- Conforming Revisions for FERC Order ER11-2287, accepted on 01/31/2011, and effective 01/31/2011 to revise the definition of an Existing Generation Resource for the purposes of must-offer and mitigation provisions (Section 1.2, 5.6.1, 5.7.1).
- Conforming Revisions needed to include updates to Installed Reserve Margin, Pool-wide average EFORd, Forecast Pool Requirement, CETO, and CETLs prior to Incremental Auctions and conform to Attachment DD of Open Access Transmission Tariff. (Sections 2.1.1, 2.1.3, 2.1.4, and 2.3)
- Conforming Revisions for FERC Order ER11-2287, accepted on 01/31/2011 and effective 02/01/2011 to establish three product alternatives (limited, extended summer, and annual) for demand resources seeking to participate in PJM's capacity market. (Sections 2.4.3, 4.3, 4.3.1, 4.3.2, 4.3.7, 5.3, 5.3.1, 5.4, 5.6.2, 5.7.5, 5.8.1, 8.2.2, 8.5, 8.5.1, 8.5.2, 8.6, 8.7, 9.1.7, 9.1.9, 11.1.3, 11.3, 11.9.1)
- Conforming Revisions for FERC Order ER11-3365, accepted on 6/6/2011 and effective 06/17/2011, to refine the calculations of the amount of capacity commitments that PJM seeks to procure or release in Incremental Auctions and the amount of Excess Committed Credits commencing with the 2012/2013 Delivery Year (Sections 3.5 and 8.7.2)
- Conforming Revisions for FERC Order ER05-1410-015, et al., accepted on 05/20/2010 to implement the use of an Updated VRR Curve Increment/Decrement in developing PJM Buy Bids/Sell Offers in Incremental Auctions (Section 3.5).
- Conforming Revisions for FERC Order ER12-125 accepted on 12/02/2011 and effective 12/19/2011 to clarify that PJM Emergency Load Response Registrations must be submitted to PJM no later than one day before the tenth business day preceding the relevant Delivery year, and must be approved on or before May 31st preceding the relevant Delivery Year (Section 4.3.7)
- Conforming Revisions for FERC Order ER10-1003, accepted on 05/05/2010, and effective 06/01/2010 to revise PJM's credit risk management rules for certain bilateral transactions (unit-specific transactions for cleared capacity, Auction Specific MW transactions, and Locational UCAP transactions) (Sections 4.6.2, 4.6.6, and 4.6.7).
- Conforming Revisions needed to clarify the Auction Credit Rate and conform to Attachment Q of Open Access Transmission Tariff. (Section 4.8.3)
- Conforming Revisions for FERC Order ER11-2913, accepted on 4/13/2011and effective 04/20/2011, to allow Credit-Limited Offers in RPM Auctions for planned resources (whether generation, demand resources, or energy efficiency) (Section 4.8.4).
- Conforming Revisions for FERC Order ER11-4143, accepted on 09/12/2011 and effective 06/01/2007, to correct time periods for critical peak periods for the

assessment of Peak Hour Period Availability from eastern prevailing time (EPT) to local prevailing time (LPT) (Section 8.4).

- Conforming Revisions for FERC Order ER09-412, accepted on 03/26/2009, and effective 06/01/2009 to allow excess available capacity that satisfies all capacity resource obligations of a committed resource to serve as replacement capacity to offset potential peak hour period availability penalties. (Sections 8.4.5 and 8.4.5.1)
- Conforming Revisions for FERC Order ER10-2917, accepted on 10/29/2010, and effective 11/23/2010 to further clarify that PJM considers committed capacity first in determining net peak hour period capacity shortfalls in an LDA and then considers uncommitted, available capacity to adjust the net peak hour period capacity shortfall in an LDA only to extent necessary to mitigate or eliminate any availability shortfalls for committed capacity (Sections 8.4.5 and 8.4.5.1).
- Conforming Revisions for FERC Order ER12-271, accepted on 12/27/2011 and effective 12/30/2011, to modify the bill timing of the Demand Resource and ILR Compliance Penalty Charge such that charges are assessed and billed in two phases. (Section 9.1.9)
- Conforming Revisions needed to clarify Fixed Resource Requirement Alternative business rules in Section 11.3 and conform to Schedule 8.1 of the Reliability Assurance Agreement.
- Conforming Revisions for FERC Order ER11-2875 regarding MOPR (Section 5.3.5)

Revision 13 (11/17/2011):

- Revisions for DEOK integration (Sections 2.3.1, 2.3.4, 3.3.1, and Attachment B)

Revision 12 (05/25/2011):

- Confirming Revisions for FERC Order ER11-2898, accepted on 04/04/2011 and effective 04/18/2011, to include changes for:
    - Requirement to provide meter data on a 24-hour basis during the day on which a Load Management event or performance test occurs and for all hours during any other days as required by PJM to calculate load reduction
    - Avoiding double assessment of a penalty (penalty for both RPM Commitment Compliance and Load Management Event or Test Compliance) for a Demand Resource
    - Modification to the load management retest rules
    - Modification and clarification of the rules for use of Demand Resources as replacement capacity
- Confirming Revisions for FERC Order ER11-1909, accepted on 12/20/2010 and effective on 12/27/2010, to include a change to clarify the definition of an EE Resource to reflect that a project qualifying as an EE Resource is one installed at an end-use customer's retail site.
- Revisions to EFORd used for a generation resource in the initial evaluation of a FRR Entity's FRR Capacity Plan for a Delivery Year as approved by stakeholders at the MRC on August 5, 2010.

Revision 11 (04/28/2011):

- Revisions for ATSI integration (Sections 2.3.1, 2.3.4, 3.3.1, and Attachment B)

Revision 10 (06/01/2010):

- Revisions made to rules for Non Unit-specific Capacity Transactions to clarify that PJM will be the counterparty to all transactions, unless market participants expressly and mutually contract between themselves (or self schedule to themselves). Revisions have been approved at the Markets and Reliability Committee on April 21, 2010 and by FERC (Order ER10-1003 issued on May 5, 2010)
- (Reference: FERC Order ER10-1003)

Revision 9 (03/01/2010):

- Clarifying Revisions
- Conforming Revisions for FERC Order ER10-15, accepted on 11/13/09 and effective 12/01/09, to include changes to Credit Rate Change
- Conforming Revisions for FERC Order ER09-1679 accepted on October 29, 2009 and effective November 1, 2009 to include changes for:
- New Entry Pricing Adjustment
- Removal of Existing EE and DR offer caps
- Allocation of LM Test Failure Charges
- Planned DR Deadline - change to 15 business days
- Excess Commitment Credit for LSEs if cannot sell excess in IA
- Reduction in FRR Obligation when Load Forecast is reduced
- Conforming Revisions for FERC Order ER05-1410 accepted on October 30, 2009 and effective 11/1/09 to include changes to Incremental Auctions design
- Conforming Revisions for FERC Order ER09-412 accepted on November 5, 2009 and effective November 13, 2009, to include changes to the trigger for a Conditional IA only for delay of Backbone Transmission Upgrade
    - Conforming Revisions for ER09-1679 to include changes to Revisions for the automated adjustment to Net CONE
    - Conforming Revisions for FERC Order ER10-366 accepted on January 22, 2010 and effective January 31, 2010, to include changes
- evaluate the method for creation of additional CONE regions
- Revisions to allow Energy Efficiency Resources to participate in Earlier Deliver Years
    - RPM Incremental Auction Times

Revision 8 (01/01/10):

- Revisions approved by stakeholders at MRC on November 11, 2009
- One CSP Rule (Section 4, p 33)
- Permanent Load Departure (Section 8, p 98)

- Tracking Existing DR (Section 4, pp 30-31)
- Revisions approved by stakeholders at MRC on November 30, 2009 (awaiting FERC approval by February 1, 2010)
- Winter Capacity Test Exemption (Sections 4 & 8, pp 24, 27, 104-105)

Revision 7 (08/18/2009):

- Revision to Section 4 to modify business rules to state that RPM suppliers must confirm the modeling of each of their capacity resources (Zone, LDA, Unit Type, State Location) prior to any RPM auction.
- Revision to Section 5 to modify business rules to state that RPM Auction Results will not be posted until 4pm or later on Friday of Auction Clearing week.

Revision 06 (06/18/2009):

- Revisions to include business rules for Cleared Buy Bid and Locational UCAP transactions.
- Revisions required as a result of the March 26, 2009 FERC Order regarding Reliability Pricing Model

Revision 05 (10/03/2008):

- Revisions regarding Transmission Service for External Resources offering into RPM.

Revision 04 (06/08/2008):

- Incorporate Rules for Capacity Export Charge per FERC Order ER07-1050
- (Effective May 30, 2008)

Revision 03 (04/01/2008):

- Established a Min and Max capacity value for Wind Resources offering into an RPM Auction.

Revision 02 (02/21/2008):

- Correct an error in the original posting of this Manual. Remove the word "not" in the End-Use Customer Aggregation section of Section 4 to reflect the fact that aggregation of Interruptible for Load (ILR) Resources is allowed.

Revision 01 (02/03/2008):

- Revisions made for the following changes:
    - Current, Minimum, Maximum Available Capacity Position Definitions.
    - Change Final Zonal RPM Scaling Factors posting date from October 31st to January 5th.
    - Allow for Combined Demand Resources and ILR Resources at the same location.

Revision 00 (06/01/07):

- Manual Created for the Implementation of the Reliability Pricing Model, and the Fixed Resource Requirement Alternative.

Kentucky Power Company

REQUEST

Please confirm that the additional energy from purchases pursuant to the REPA will increase the energy available for sale into the market, all else equal.

RESPONSE

Assuming the approval of the Mitchell transfer in Case No. 2012-00578 and converting Big Sandy Unit 1 to gas or accepting a bid(s) for all 250MWs in its current RFP solicitation, the Company confirms the above statement.

WITNESS: Jay F. Godfrey/Gregory G. Pauley

Kentucky Power Company

REQUEST

If the Company agrees that the additional energy from purchases pursuant to the REPA will increase energy available for sale into the market, then does the Company propose any modification of the System Sales Clause so that the margins from such increased sales are allocated 100% to customers rather than the allocation of 60% to customers and 40% to the Company under the present SSC? Please explain your response and provide all reasons for the Company's position on sharing these incremental margins between customers and the Company.

RESPONSE

No. The current 60/40 split between customers and the Company is a fair, just and reasonable allocation as approved in the settlement to Case No. 2009-00459. Any proposed changes to this allocation should be addressed in the Company's next base rate filing.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please confirm that the Company plans to treat the REPA as "must run," meaning that it will purchase all energy produced by the facility without regard to economic dispatch.

RESPONSE

The Company confirms that it will purchase all energy produced by the facility. The Company has no control over when EcoPower will submit its facility into the daily PJM market. Please see sections 5.3 and 5.6 of the REPA.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Please provide all reports, studies, and other documentation of the construction costs and operating expenses of the proposed facility.

RESPONSE

Please see KIUC 1-24 CONFIDENTIAL Attachment 1. In addition, please see CONFIDENTIAL Attachment 2 provided in the Company's response to KIUC 1-14. Confidential treatment is being sought for KIUC 1-24 Attachment 1 in entirety.

WITNESS: Jay F Godfrey

KIUC 1-24 ATTACHMENT 1 REDACTED IN ENTIRETY

Kentucky Power Company

REQUEST

Please provide all reports, studies, and other documentation of the construction costs and operating expenses of other biomass facilities similar to the proposed facility.

RESPONSE

The Company does not have the requested information.

WITNESS: Jay F Godfrey