ARTICLE 9 -- COORDINATED PLANNING AND OPERATION

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

9.1 Overall Coordination.

Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with the Reliability Principles and Standards. In furtherance of such cooperation each Party shall:

(a)

cooperate with the members and associate members of such Party's Applicable Regional Reliability Council to ensure the reliability of the region;

(b) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM Region for Operating Reserves;

(c) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service;

(d) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards;

(e) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies; and

(f) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection.

9.2 Generator Planned Outage Scheduling.

Each Party shall develop, or cause to be developed, its schedules of planned outages of its Capacity Resources. Such schedules of planned outages shall be submitted to the Office of the Interconnection for coordination with the schedules of planned outages of other Parties and anticipated transmission planned outages.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

9.3 Data Submissions.

Each Party shall submit to the Office of the Interconnection the data and other information necessary for the performance of this Agreement as may be more fully described, in Schedule 11 hereof.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

9.4 Charges for Failures to Comply.

(a) An emergency procedure charge, as set forth in Attachment DD to the PJM Tariff, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection in times of Emergencies.

(b) A data submission charge, as set forth in Schedule 12, shall be imposed on any Party that fails to submit the data, plans or other information required by this Agreement in a timely or accurate manner as provided in Schedule 11.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

9.5 Metering.

Each Party shall comply with the metering standards for the PJM Region, as set forth in the PJM Manuals.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 10 -- SHARED COSTS

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

10.1 Recording and Audit of Costs.

(a) Any costs related to the performance of this Agreement, including the costs of the Office of the Interconnection and such other costs that the Members Committee determines are to be shared by the Parties, shall be documented and recorded in a manner acceptable to the Parties.

(b) The Members Committee may require an audit of such costs; provided, however, the cost records shall be available for audit by any Member or State Consumer Advocate, at the sole expense of such Member or State Consumer Advocate, for 36 months following the end of the Planning Period in which the costs were incurred.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

10.2 Cost Responsibility.

The costs determined under Section 10.1(a) shall be allocated to and recovered from the Parties to this Agreement and other entities pursuant to Schedule 9-5 of the PJM Tariff.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 11 -- BILLING AND PAYMENT

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

11.1 Periodic Billing.

Each Party shall receive a statement periodically setting forth (i) any amounts due from or to that Party as a result of any charges imposed pursuant to this Agreement and (ii) that Party's share of any costs allocated to that Party pursuant to Article 10. To the extent practical, such statements are to be coordinated with any billings or statements required pursuant to the Operating Agreement or PJM Tariff.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

11.2 Payment.

The payment terms and conditions shall be as set forth in the billing statement and shall, to the extent practicable, be the same as those then in effect under the PJM Tariff.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

11.3 Failure to Pay.

If any Party fails to pay its share of the costs allocated pursuant to Article 10, those unpaid costs shall be allocated to and paid by the other Parties hereto in proportion to the sum of the Daily Unforced Capacity Obligations of each such Party for the billing month. The Office of the Interconnection shall enforce collection of a Party's share of the costs.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 12 -- INDEMNIFICATION AND LIMITATION OF LIABILITIES

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

12.1 Indemnification.

(a) Each Party agrees to indemnify and hold harmless each of the other Parties, its officers, directors, employees or agents (other than PJM Interconnection, L.L.C., its board or the Office of the Interconnection) for all actions, claims, demands, costs, damages and liabilities asserted by third parties against the Party seeking indemnification and arising out of or relating to acts or omissions in connection with this Agreement of the Party from which indemnification is sought, except (i) to the extent that such liabilities result from the willful misconduct of the Party seeking indemnification and (ii) that each Party shall be responsible for all claims of its own employees, agents and servants growing out of any workmen's compensation law. Nothing herein shall limit a Party's indemnity obligations under Article 16 of the Operating Agreement.

(b) The amount of any indemnity payment under this Section 12.1 shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Party seeking indemnification in respect of the indemnified actions, claims, demands, costs, damages or liabilities. If any Party shall have received an indemnity payment in respect of an indemnified action, claim, demand, cost, damage, or liability and shall subsequently actually receive insurance proceeds or other amounts in respect of such action, claim, demand, cost, damage, or liability, then such Party shall pay to the Party that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

12.2 Limitations on Liability.

No Party will be liable to another Party for any claim for indirect, incidental, special or consequential damage or loss of the other Party including, but not limited to, loss of profits or revenues, cost of capital or financing, loss of goodwill and cost of replacement power arising from such Party's carrying out, or failure to carry out, any obligations contemplated by this Agreement; provided, however, nothing herein shall be deemed to reduce or limit the obligation of any Party with respect to the claims of persons or entities not a party to this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

12.3 Insurance.

Each Party shall obtain and maintain in force such insurance as is required of Load Serving Entities by the states in which it is doing business within the PJM Region.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 13 -- SUCCESSORS AND ASSIGNS

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

13.1 Binding Rights and Obligations.

The rights and obligations created by this Agreement and all Schedules and supplements thereto shall inure to and bind the successors and assigns of the Parties; provided, however, no Party may assign its rights or obligations under this Agreement without the written consent of the Members Committee unless the assignee concurrently becomes the Load Serving Entity with regard to the end-users previously served by the assignor.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

13.2 Consequences of Assignment.

Upon the assignment of all of its rights and obligations hereunder to a successor consistent with the provisions of Section 13.1, the assignor shall be deemed to have withdrawn from this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 14 -- NOTICE

Except as otherwise expressly provided herein, any notice required hereunder shall be in writing and shall be sent: overnight courier, hand delivery, telecopy or other reliable electronic means to the representative on the Members Committee of such Party at the address for such Party previously provided by such Party to the other Parties. Any notice shall be deemed to have been given (i) upon delivery if given by overnight courier, hand delivery or certified mail or (ii) upon confirmation if given by facsimile or other reliable electronic means.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 15 -- REPRESENTATIONS AND WARRANTIES

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

15.1 Initial Representations and Warranties.

Each Party represents and warrants to the other Parties that, as of the date it becomes a Party:

(a) the Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

(b) the execution and delivery by the Party of this Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict with any applicable law or with any other agreement binding upon the Party. The Agreement has been duly executed and delivered by the Party, and this Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity; and

(c) there are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

15.2 Continuing Representations and Warranties.

Each Party represents and warrants to the other Parties that throughout the term of this Agreement:

(a) the Party is a Load Serving Entity;

(b) the Party satisfies the requirements of Schedule 2;

(c) the Party is in compliance with the Reliability Principles and Standards;

(d) the Party is a signatory, or its principals are signatories, to the agreements set forth in Schedule 3;

(e) the Party is in good standing in the jurisdiction where incorporated; and

(f) the Party will endeavor in good faith to obtain any corporate or regulatory authority necessary to allow the Party to fulfill its obligations hereunder.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 16 -- OTHER MATTERS

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.1 Relationship of the Parties.

This Agreement shall not be interpreted or construed to create any association, joint venture, or partnership between or among the Parties or to impose any partnership obligation or partnership liability upon any Party.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.2 Governing Law.

This Agreement shall be interpreted, construed and governed by the laws of the State of Delaware.

16.3 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.4 Amendment.

This Agreement may be amended only by action of the PJM Board. Notwithstanding the foregoing, an Applicant eligible to become a Party in accordance with the procedures set forth in Article 4 shall become a Party by executing a counterpart of this Agreement without the need for execution of such counterpart by any other Party. The PJM Office of the Interconnection shall file with FERC any amendment to this Agreement approved by the PJM Board.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.5 Headings.

The article and section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.6 Confidentiality.

(a) No Party shall have a right hereunder to receive or review any documents, data or other information of another Party, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection or to the extent that they have been designated as confidential by another Party; provided, however, a Party may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite document does not disclose any individual Party's confidential data or information.

(b) Notwithstanding anything in this Section to the contrary, if a Party is required by applicable laws, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section, that Party may make disclosure of such information; provided, however, that as soon as the Party learns of the disclosure requirement and prior to making disclosure, that Party shall notify the affected Party or Parties of the requirement and the terms thereof and the affected Party or Parties may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement and the Party shall cooperate with such affected Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. Each Party shall cooperate with the affected Parties to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(c) Any contract with a contractor retained to provide technical support or to otherwise assist with the administration of this Agreement shall impose on that contractor a contractual duty of confidentiality that is consistent with this Section.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.7 Counterparts.

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon all parties hereto, notwithstanding that all of such parties may not have executed the same counterpart.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.8 No Implied Waivers.

The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.9 No Third Party Beneficiaries.

This Agreement is intended to be solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any third party not a signatory hereto.

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16.10 Dispute Resolution.

Except as otherwise specifically provided in the Operating Agreement, disputes arising under this Agreement shall be subject to the dispute resolution provisions of the Operating Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

[Signatures]

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 1

PROCEDURES TO BECOME A PARTY

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

A. Notice

Any entity that is or will become a Load Serving Entity within the PJM Region and thus a Party to the Reliability Assurance Agreement shall submit a notice to the Office of the Interconnection together with (i) its representation that it has satisfied or will (prior to the date the Reliability Assurance Agreement is to become effective as to that entity) satisfy the requirements to become a Party, (ii) all data required to coordinate planning and operations within the PJM Region as applicable, in a format defined in the PJM Manuals, and (iii) a deposit in an amount to be specified that will be applied toward the costs of the required analysis.

The required notice, representations, data and deposit must be submitted in sufficient time to conduct an analysis of the data submitted and to adjust the obligations of the Parties for the month in which the entity desires to become a Party:

- If the then existing boundaries of the PJM Region would be expanded by an entity becoming a Party, that entity shall submit the required notice, representation, data and deposit no later than when the entity applies for transmission service under the PJM Tariff.

- If an entity will serve load within the then existing boundaries of the PJM Region, that entity shall submit the required notice, representations, data and deposit as soon as possible prior to the month (i) in which it is to begin serving loads within the PJM Region or (ii) in which any agency relationship through which the entity's obligations under this Agreement had been satisfied is terminated; provided, however, that such submission shall not be required sooner than any request for transmission service or any change in the designation of Network Resources or points of receipt and loads under the PJM Tariff associated with providing service to those loads.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

B. Analysis of Data

The notice, representations and data submitted to the Office of the Interconnection are to be analyzed in accordance with procedures consistent with this Agreement and the encouragement of reliable operation of the PJM Region.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

C. Response

Upon completion of the analysis, the Office of the Interconnection will inform the entity of (a) the estimated costs and expenses associated with modifications to communication, computer and other facilities and procedures, including any filing fees, needed to include the entity as a Party, (b) the entity's share of any costs pursuant to Article 10, and (c) the earliest date upon which the entity could become a Party. In addition, a counterpart of the Agreement shall be forwarded for execution.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

D. Agreement by New Party

After receipt of the response from the Office of the Interconnection, the entity shall identify its representative to the Members Committee and Markets and Reliability Committee and execute the counterpart of the Agreement, indicating the desired effective date; provided, however, such effective date shall be the first day of a month, may be no earlier than the date indicated in the response from the Office of the Interconnection and shall be no later than (i) the date on which the entity begins serving loads within the PJM Region or (ii) the termination date of any agency relationship through which its obligations under this Agreement had been satisfied. The executed counterpart of the Agreement, together with payment of its share of any costs then due, shall be returned as directed by the Office of the Interconnection.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 2

STANDARDS FOR INTEGRATING AN ENTITY INTO THE PJM REGION

A. The following standards will be applied by the Office of the Interconnection to determine the eligibility of an entity to become a part of the PJM Region. For an entity to be integrated into the PJM Region it must possess generation and transmission attributes that would enable the entity to share its reserves with other entities in the PJM Region. Appropriate transmission and reliability studies are to be performed to determine the adequate transmission capability necessary to integrate the entity into the PJM Region consistent with Good Utility Practice.

B. In addition, the entity shall meet the following requirements to be included in the PJM Region:

1. All load, generation and transmission operating as part of the PJM Region's interconnected system must be included within the metered boundaries of the PJM Region.

2. The entity will accept and comply with the PJM Region's standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region.

3. The load, generation and transmission facilities of each entity shall be included in the telemetry to the Office of the Interconnection from a 24-hour control center. Each system operator in these control centers must be trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner.

4. Each entity must have compatible operational communication mechanisms, maintained at its expense, to interact with the Office of the Interconnection and for internal requirements.

5. Each entity must assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the Office of the Interconnection as it directs the operation of the PJM Region.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 3

OTHER AGREEMENTS TO BE EXECUTED BY THE PARTIES

- Any agreement for Network Transmission Service or Firm Point-To-Point Service that is required under the PJM Tariff for service consistent with the requirements of Section 9.1(d); and

- The Operating Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 4

GUIDELINES FOR DETERMINING THE FORECAST POOL REQUIREMENT

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

A. Objective Of The Forecast Pool Requirement

The Forecast Pool Requirement shall be determined for the specified Planning Periods to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

B. Forecast Pool Requirement and PJM Region Installed Reserve Margin To Be Determined Annually

No later than three months in advance of each Base Residual Auction for a Delivery Year, based on the projections described in section C of this Schedule, and after consideration of the recommendation of the Members Committee, the PJM Board shall establish the Forecast Pool Requirement, including the PJM Region Installed Reserve Margin for all Parties, including FRR Entities, for such Delivery Year. Unless otherwise agreed by the PJM Board, the Forecast Pool Requirement and PJM Region Installed Reserve Margin for such Planning Period shall be considered firm and not subject to re-determination thereafter.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

C. Methodology

Each year, the Forecast Pool Requirement for at least each of the next five Planning Periods shall be projected by applying suitable probability methods to the data and forecasts provided by the Parties and obtained from Electric Distributors, as described in Schedule 11, the Operating Agreement and in the PJM Manuals. The projection of the Forecast Pool Requirement shall consider the following data and forecasts as necessary:

1. Seasonal peak load forecasts for each Planning Period as calculated by PJM in accordance with the PJM Manuals reflecting (a) load forecasts with a 50 percent probability of being too high or too low and (b) summer peak diversities determined by the Office of the Interconnection from recent experience.

2. Forecasts of aggregate seasonal load shape of the Parties which are consistent with forecast averages of 52 weekly peak loads prepared by the Parties and obtained from Electric Distributors for their respective systems.

3. Variability of loads within each week, due to weather and other recurring and random factors, as determined by the Office of the Interconnection.

4. Generating unit capability and types for every existing and proposed unit.

5. Generator Forced Outage rates for existing mature generating units, as determined by the Office of the Interconnection, based on data submitted by the Parties for their respective systems, from recent experience, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

6. Generator Maintenance Outage factors and planned outage schedules as determined by the Office of the Interconnection based on forecasts and historical data submitted by the Parties for their respective systems.

7. Miscellaneous adjustments to capacity due to all causes, as determined by the Office of the Interconnection, based on forecasts submitted by the Parties for their respective systems.

8. The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, as limited by the capacity benefit margin considered in the determination of available transfer capability and the probable availability of generation in excess of load requirements in such areas.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

D. Capacity Benefit Margin

The capacity benefit margin initially shall be 3,500 megawatts. Periodically, in consultation with the Members Committee, the Office of the Interconnection shall review and modify, if necessary, the capacity benefit margin to balance external emergency capacity assistance and internal installed capacity reserves so as to minimize the total cost of the capacity reserves of the Parties, consistent with the Reliability Principles and Standards. The Office of the Interconnection will reflect such modification prospectively in its development of the Forecast Pool Requirement for future Planning Periods.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 4.1

DETERMINATION OF THE FORECAST POOL REQUIREMENT

A. Based on the guidelines set forth in Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (1 + IRM/100) * (1 - \text{Pool-wide average } EFOR_D/100)$$

where

average $EFOR_D$ = the average equivalent demand forced outage rate for the PJM Region, stated in percent and determined in accordance with Section B hereof

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent. Studies by the Office of the Interconnection to determine IRM shall not exclude outages that are deemed to be outside plant management control under NERC guidelines.

B. The PJM Region equivalent demand forced outage rate ("average $EFOR_D$") shall be determined as the capacity weighted $EFOR_D$ for all units expected to serve loads within the PJM Region during the Delivery Year, as determined pursuant to Schedule 5.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 5

FORCED OUTAGE RATE CALCULATION

A. The equivalent demand forced outage rate ("$EFOR_D$") shall be calculated as follows:

$$EFOR_D\ (\%) = \{(f_f * FOH + f_p * EFPOH) / (SH + f_f * FOH)\} * 100$$

where

f_f = full outage factor
f_p = partial outage factor
FOH = full forced outage hours
EFPOH = equivalent forced partial outage hours
SH = service hours

B. Calculation of $EFOR_D$ for individual Generation Capacity Resources.

For each Delivery Year, $EFOR_D$ shall be calculated at least one month prior to the start of the Third Incremental Auction for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third Incremental Auction; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to an FRR Capacity Plan or prior auctions for such Delivery Year. Such calculation shall be based upon such resource's service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit. For purposes of the calculations under this Paragraph B, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered.

1. The $EFOR_D$ of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

2. The $EFOR_D$ of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the $EFOR_D$ experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average $EFOR_D$ for the PJM Region

The forecast average $EFOR_D$ for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average $EFOR_D$ shall be the average of the capacity-weighted $EFOR_Ds$ of all units committed to serve load in the PJM Region; and for purposes of the $EFOR_D$ calculations under this Paragraph C for any Delivery Year beginning after May 31, 2010, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered. All rates shall be in percent.

1. The $EFOR_D$ of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.

2. The $EFOR_D$ of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.

3. The $EFOR_D$ of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar Years of Service	
1	One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate.
2	Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate.
3	Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
4	Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES, ILR, AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources or ILR that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. In addition, for Delivery Years through May 31, 2012, resources qualifying under the criteria set forth below may be certified as ILR on behalf of a Party that has not elected the FRR Alternative for a Delivery Year no later than three months prior to the first day of such Delivery Year; provided, however, that for the 2011-2012 Delivery Year only, the ILR certification deadline shall be no later than two months prior to the first day of such Delivery Year. Qualified Demand Resources and ILR generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Direct Load Control, as further specified in section H and the PJM Manuals. Qualified Demand Resources and ILR may be provided by a Demand Resource Provider or ILR Provider (hereinafter, "Provider"), notwithstanding that such Provider is not a Party to this Agreement. Such Providers must satisfy the requirements in section I and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and paragraph G of this schedule as applicable, the Office of the Interconnection of the Demand Resource or ILR that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is an ILR resource, a Limited Demand Resource, an Extended Summer Demand Resource or an Annual Demand Resource.

2. A period of no more than 2 hours prior notification must apply to interruptible customers.

3. The initiation of load interruption, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered an emergency action and must be implementable prior to a voltage reduction.

5. An entity offering for sale, designating for self-supply, or including in any FRR Capacity Plan any Planned Demand Resource must demonstrate, in accordance with standards and procedures set forth in the PJM Manuals, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. Providers of Planned Demand Resources must provide a timeline including the milestones, which demonstrates to PJM's satisfaction that the Planned Demand Resources will be available for the start of the Delivery Year, 15 business days prior to a Base Residual Auction or Incremental Auction. PJM may verify the Provider's adherence to the timetable at any time.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response program and thus available for dispatch during PJM-declared emergency events.

B. The Unforced Capacity value of a Demand Resource and ILR will be determined as:

the product of the Nominated Value of the Demand Resource, or the Nominated Value of the ILR, times the DR Factor, times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections J and K, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR, divided by the total Nominated Value of Demand Resources and ILR in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources and ILR, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Demand Resource Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. Certified ILR resources shall receive the Final Zonal ILR Price.

E. The Party, Electric Distributor, Demand Resource Provider, or ILR Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in sections C and D for a committed Demand Resource or certified ILR, notwithstanding that such provider is not the customer's energy supplier.

F. Any Party hereto shall demonstrate that its Demand Resources or ILR performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section L and the PJM Manuals. In addition, committed Demand Resources and certified ILR that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

G. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

H. PJM recognizes three types of Demand Resource and ILR:

Direct Load Control (DLC) – Load management that is initiated directly by the Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for DLC programs. Each Provider relying on DLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

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 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 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 Demand Resource and ILR above, there can be two notification periods:

Step 1 (Short Lead Time) – Demand Resource or ILR 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) – Demand Resource or ILR 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.

I. Each Provider must satisfy (or contract with another LSE, Provider, or EDC to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- supplemental status reports, detailing Demand Resources and ILR available, as requested by PJM;

- Entry of customer-specific Demand Resource and ILR credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource or ILR event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource or ILR events, prepared in accordance with the PJM Manuals.

J. The Nominated Value of each Demand Resource or ILR shall be determined consistent with the process for determination of the capacity obligation for the customer.

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 utilized to determine other ICAP obligation values. The maximum Demand Resource or ILR load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

The Nominated Value for a Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource or ILR information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections K and L.

K. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource or ILR information, to verify the amount of load management available, and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource, or certification of such resource as ILR. Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

For Direct Load Control programs, the Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

L. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource and ILR events. Compliance will be established for each Provider on an event specific basis for the Provider's Demand Resources or ILR dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

Compliance for Direct Load Control programs will consider only the transmission of the control signal. Providers are required to report the time period (during the Demand Resource and ILR event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for GLD, and will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(iii) Providers must submit actual loads and comparison loads for all hours during the day of the Load Management event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the full hours of a load management event, for each customer or DLC program dispatched by the Office of the Interconnection. Demand Resource or ILR resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and DLC programs to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed and ILR Certified by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

M. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described herein) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value, which shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday. The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a

Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

Effective Date: 11/7/2011 - Docket #: ER11-3322-001

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify the Office of the Interconnection via the Internet site designated by the Office of the Interconnection, prior to the start of the Base Residual Auction for such Delivery Year.

B. A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff.

C. If, at any time after the close of the Third Incremental Auction for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

SCHEDULE 8

DETERMINATION OF UNFORCED CAPACITY OBLIGATIONS

A. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of a Party that has not elected the FRR Alternative for such Delivery Year shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = OPL x Final Zonal RPM Scaling Factor x FPR

Where:

OPL =Obligation Peak Load, defined as the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal RPM Scaling Factor = the factor determined as set forth in sections B and C of this Schedule

FPR = the Forecast Pool Requirement

Netting of Behind the Meter Generation for a Party with regard to Non-Retail Behind the Meter Generation shall be subject to the following limitation:

For the 2006/2007 Planning Period, 100 percent of the operating Non-Retail Behind the Meter Generation shall be netted, provided that the total amount of Non-Retail Behind the Meter Generation in the PJM Region does not exceed 1500 megawatts ("Non-Retail Threshold"). For each Planning Period/Delivery Year thereafter, the Non-Retail threshold shall be proportionately increased based on load growth in the PJM Region but shall not be greater than 3000 megawatts. Load growth shall be determined by the Office of the Interconnection based on the most recent forecasted weather-adjusted coincident summer peak for the PJM Region divided by the weather-adjusted coincident peak for the previous summer for the same area. After the load growth factor is applied, the Non-Retail Threshold will be rounded up or down to the nearest whole megawatt and the rounded number shall be the Non-Retail Threshold for the current Planning Period and the base amount for calculating the Non-Retail Threshold for the succeeding planning period. If the Non-Retail Threshold is exceeded, the amount of operating Non-Retail Behind the Meter Generation that a Party may net shall be adjusted according to the following formula:

Party Netting Credit = (NRT/ PJM NRBTMG) * Party Operating NRBTMG

Where: NRBTMG is Non-Retail Behind the Meter Generation

NRT is the Non-Retail Threshold

PJM NRBTMG is the total amount of Non-Retail Behind the Meter Generation in the PJM Region

The total amount of Non-Retail Behind the Meter Generation that is eligible for netting in the PJM Region is 3000 megawatts. Once this 3000 megawatt limit is reached, any additional Non-Retail Behind the Meter Generation which operates in the PJM Region will be ineligible for netting under this section.

In addition, the Party NRBTMG Netting Credit shall be adjusted pursuant to Schedule 16 of this Agreement, if applicable.

A Party shall be required to report to PJM such information as is required to facilitate the determination of its NRBTMG Netting Credit in accordance with the procedures set forth in the PJM Manuals.

B. Following the Base Residual Auction for a Delivery Year, the Office of the Interconnection shall determine the Base Zonal RPM Scaling Factor and the Base Zonal Unforced Capacity Obligation for each Zone for such Delivery Year as follows:

Base Zonal Unforced Capacity Obligation = (ZWNSP * Base Zonal RPM Scaling Factor * FPR) + Forecast Zonal ILR Obligation (for Delivery Years through May 31, 2012) or Zonal Short-Term Resource Procurement Target (for Delivery Years thereafter)

and

Base Zonal RPM Scaling Factor = ZPLDY/ZWNSP x [RUCO / (RPLDY x FPR)]

Where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Delivery Year

ZWNSP = Zonal Weather-Normalized Summer Peak for the summer season concluding four years prior to the commencement of such Delivery Year

RUCO = the RTO Unforced Capacity Obligation satisfied in the Base Residual Auction for such Delivery Year.

RPLDY = RTO Preliminary Peak Load Forecast for such Delivery Year.

For purposes of such determination, PJM shall determine the Preliminary RTO Peak Load Forecast, and the Preliminary Zonal Peak Load Forecasts for each Zone, in accordance with the PJM Manuals for each Delivery Year no later than one month prior to the Base Residual Auction for such Delivery Year. PJM shall determine the Updated RTO and Zonal Peak Load Forecasts in accordance with the PJM Manuals for each Delivery Year no later than one month prior to each of the First, Second, and Third Incremental Auctions for such Delivery Year. PJM shall determine the most recent Weather Normalized Summer Peak for each Zone no later than seven months prior to the start of the Delivery Year, and shall calculate the RTO Weather Normalized Summer Peak as the sum of the Weather Normalized Summer Peaks for all Zones.

C. The Final RTO Unforced Capacity Obligation for a Delivery Year shall be equal to the sum of the unforced capacity obligations satisfied through the Base Residual Auction and the First, Second, Third, and any Conditional Incremental Auctions for such Delivery Year. The unforced capacity obligation satisfied in an Incremental Auction may be negative if capacity is decommitted in such auction. The Final Zonal Unforced Capacity Obligation for a Zone shall be equal to such Zone's pro rata share of the Final RTO Unforced Capacity Obligation for the Delivery Year based on the Final Zonal Peak Load Forecast made one month prior to the Third Incremental Auction The Final Zonal RPM Scaling Factor shall be equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Summer Peak for the summer concluding prior to the commencement of such Delivery Year).

D. 1. No later than five months prior to the start of each Delivery Year, the Electric Distributor for a Zone shall allocate the most recent Weather Normalized Summer Peak for such Zone to determine the Obligation Peak Load for each end-use customer within such Zone.

2. During the Delivery Year, no later than 36 hours prior to the start of each operating day, the Electric Distributor shall provide to PJM for each Party to this Agreement serving load in such Electric Distributor's Zone the Obligation Peak Load for all end-use customers served by such Party in such Zone. The daily Unforced Capacity Obligation of a Party for such Operating Day shall not be subject to change thereafter.

3. For purposes of such allocations, the daily sum of the Obligation Peak Loads of all Parties serving load in a Zone must equal the Zonal Obligation Peak Load for such Zone.

SCHEDULE 8.1

FIXED RESOURCE REQUIREMENT ALTERNATIVE

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

The Fixed Resource Requirement ("FRR") Alternative

A. The Fixed Resource Requirement ("FRR") Alternative provides an alternative means, under the terms and conditions of this Schedule, for an eligible Load-Serving Entity to satisfy its obligation hereunder to commit Unforced Capacity to ensure reliable service to loads in the PJM Region.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

B. Eligibility

1. A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.

2. A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

C. Election, and Termination of Election, of FRR Alternative

1. No less than two months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. The set of Capacity Resources designated in the FRR Capacity Plan must meet the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement and the PJM Operating Agreement applicable to Capacity

Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted 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 FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity.

5. For each LDA for which the Office of the Interconnection has established a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA. Such minimum percentage ("Percentage Internal Resources Required") will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement.

6. An FRR Entity may reduce such minimum percentage as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the capacity emergency transfer limit for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days of the submittal of the FRR Capacity Plan. If the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's

capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

E. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

1. An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource that has cleared in any auction under Attachment DD of the PJM Tariff for such Delivery Year. Nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan any Capacity Resource that has not cleared such an auction for such Delivery Year. Furthermore, nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan a Capacity Resource obtained from a different FRR Entity, provided, however, that each FRR Entity shall be individually responsible for meeting its capacity obligations hereunder, and provided further that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year.

2. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in any auction conducted under Attachment DD of the PJM Tariff for such Delivery Year, but may not offer to sell Capacity Resources in the auctions for any such Delivery Year in excess of an amount equal to the lesser of (a) 25% times the Unforced Capacity equivalent of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan(s) for such Delivery Year, or (b) 1300 MW.

3. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may not offer to sell such resources in any Reliability Pricing Model auction, but may use such resources to meet any increased capacity obligation resulting from unanticipated growth of the loads in its FRR Capacity Plan(s), or may sell such resources to serve loads located outside the PJM Region, or to another FRR Entity, subject to subsection E.1 above.

4. A Party that has selected the FRR Alternative for only part of its load in the PJM Region pursuant to Section B.2 of this Schedule that designates Capacity Resources as Self-Supply in a Reliability Pricing Model Auction to meet such Party's expected Daily Unforced Capacity Obligation under Schedule 8 shall not be required, solely as a result of such designation, to identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity; provided, however, that such Party may not so designate Capacity Resources in an amount in excess of the lesser of (a) 25% times such Party's total expected Unforced Capacity obligation (under both Schedule 8 and Schedule 8.1), or (b) 200 MW. A Party that wishes to avoid the foregoing limitation must identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity.

F. FRR Daily Unforced Capacity Obligations and Deficiency Charges

1. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = OPL * Final Zonal FRR Scaling Factor * FPR

where:

OPL =Obligation Peak Load, defined as the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal FRR Scaling Factor = FZPLDY/FZWNSP;

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.

2. An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in such entity's FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Such FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times (1.20 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 quantities cleared in such auctions).

3. If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of this Schedule.

4. The shortages in meeting the minimum requirement within the constrained zones and the shortage in meeting the total obligation are first calculated. The shortage in the unconstrained area is calculated as the total shortage less shortages in constrained zones and excesses in constrained zones (the shortage is zero if this is a negative number). The Capacity Deficiency Charge is charged to the shortage in each zone and in the unconstrained area separately. This procedure is used to allow the use of capacity excesses from constrained zones to reduce shortage in the unconstrained area and to disallow the use of capacity excess from unconstrained area to reduce shortage in constrained zones.

5. The shortages in meeting the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation

are calculated separately. The applicable penalty rate is calculated for Annual Resources, Extended Summer Demand Resources, and Limited Resources as (1.20 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 quantities cleared in such auctions).

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

G. Capacity Resource Performance

Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in sections 7, 9, 10, 11, and 13 of Attachment DD to the PJM Tariff; provided, however, the Daily Deficiency Rate under sections 7, 9, and 13 thereof shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions), and the charge rates under section 10 thereof, shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Sections 7, 9, and 10 of Attachment DD to the PJM Tariff. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

H. Annexation of service territory by Public Power Entity

1. In the event a Public Power Entity that is an FRR Entity annexes service territory to include new customers on sites where no load had previously existed, then the incremental load on such a site shall be treated as unanticipated load growth, and such FRR Entity shall be required to commit sufficient resources to cover such obligation in the relevant Delivery Year.

2. In the event a Public Power Entity that is an FRR Entity annexes service territory to include load from a Party that has not elected the FRR Alternative, then:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, such acquiring FRR Entity shall meet its obligations for the incremental load by paying PJM for incremental obligations (including any additional demand curve obligation) at the Capacity Resource Clearing Price for the relevant location. Any such revenues shall be used to pay Capacity Resources that cleared in the BRA for that LDA.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, such acquiring FRR Entity shall include such incremental load in its FRR Capacity Plan.

3. Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR entity:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, PJM would consider shifted load as unanticipated load growth for purposes of determining whether to hold a Second Incremental Auction. If a Second Incremental Auction is held, FRR entity would have a must offer requirement for sufficient capacity to meet the load obligation of such shifted load. If no Second Incremental Auction is conducted, the FRR Entity may sell the associated quantity of capacity into an RPM Auction or bilaterally.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, the FRR Entity that lost such load would no longer include such load in its FRR Capacity Plan, and PJM would include such shifted load in future BRAs.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

I. Savings Clause for State-Wide FRR Program

Nothing herein shall obligate or preclude a state, acting either by law or through a regulatory body acting within its authority, from designating the Load Serving Entity or Load Serving Entities that shall be responsible for the capacity obligation for all load in one or more FRR Service Areas within such state according to the terms and conditions of that certain Settlement Agreement dated September 29, 2006 in FERC Docket Nos. ER05-1410 and El05-148, the PJM Tariff and this Agreement. Each LSE subject to such state action shall become a Party to this Agreement and shall be deemed to have elected the FRR Alternative.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

SCHEDULE 9

PROCEDURES FOR
ESTABLISHING THE CAPABILITY OF GENERATION CAPACITY RESOURCES

A. Such rules and procedures as may be required to determine and demonstrate the capability of Generation Capacity Resources for the purposes of meeting a Load Serving Entity's obligations under the Agreement shall be developed by the Office of Interconnection and maintained in the PJM Manuals.

B. The rules and procedures for determining and demonstrating the capability of generating units to serve load in the PJM Region shall be consistent with achieving uniformity for planning, operating, accounting and reporting purposes.

C. The rules and procedures shall recognize the difference in types of generating units and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, and system operating policies.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 10

PROCEDURES FOR ESTABLISHING DELIVERABILITY OF GENERATION CAPACITY RESOURCES

Generation Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Region that may have a capacity deficiency at any time. Deliverability shall be demonstrated by either obtaining or providing for Network Transmission Service or Firm Point-To-Point Transmission Service within the PJM Region such that each Generation Capacity Resource is either a Network Resource or a Point of Receipt, respectively. In addition, for Generation Capacity Resources located outside the metered boundaries of the PJM Region that are used to meet an Unforced Capacity Obligation, the capacity and energy of such Generation Capacity Resources must be delivered to the metered boundaries of the PJM Region through firm transmission service.

Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide that service consistent with the assessment of available transfer capability as set forth in the PJM Tariff and, for Generation Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained or provided for Network Transmission Service or Firm Point-to-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS

The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

A. The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in Schedule 15), combinations of such Zones, and portions of such Zones:

- ATSI
- DEOK
- Dominion
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APS
- AE
- BGE
- DPL
- PECO
- PEPCO
- PSEG
- JCPL
- MetEd
- PPL
- Mid-Atlantic Area Council (MAAC) Region (consisting of all the zones listed below for Eastern MAAC, Western MAAC, and Southwestern MAAC)
- ComEd, AEP, Dayton, APS, Duquesne, ATSI, and DEOK
- Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL & RE)
- Southwestern MAAC (PEPCO & BG&E)
- Western MAAC (Penelec, MetEd, PPL)
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal

The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into PJM prior to the commencement of the Base Residual Auction for the Delivery Year for which the locational capacity obligation is being determined.

B. For purposes of evaluating the need for any changes to the foregoing list, Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction. The Locational Deliverability Areas identified in Paragraph A above (as it may be amended from time to time) for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year. If the Office of the Interconnection includes a new Locational Deliverability Area in the Regional Transmission Expansion Planning Protocol, it shall make a filing with FERC to amend this Schedule to add a new Locational Deliverability Area (including a new aggregate LDA), if such new Locational Deliverability Area is projected to have a capacity emergency transfer limit less than 1.15 times the capacity emergency transfer objective of such area, or if warranted by other reliability concerns consistent with the Reliability Principles and Standards. In addition, any Party may propose, and the Office of the Interconnection shall evaluate, consistent with the same CETO/CETO comparison or other reliability concerns, possible new Locational Deliverability Areas (including aggregate LDAs) for inclusion under the Regional Transmission Expansion Planning Protocol and for purposes of determining locational capacity obligations hereunder.

C. For each Locational Deliverability Area for which a separate VRR Curve was established for a Delivery Year, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, the Percentage of Internal Resources Required, that must be committed during such Delivery Year from Capacity Resources physically located in such Locational Deliverability Area.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

SCHEDULE 11

DATA SUBMITTALS

To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.

2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.

3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.

4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources shall be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

SCHEDULE 12

DATA SUBMISSION CHARGES

A. Data Submission Charge

For each working day of delay in the submittal of information required to be submitted under this Agreement, a data submission charge of $500 shall be imposed.

B. Distribution Of Data Submission Charge Receipts

1. Each Party that has satisfied its obligations for data submittals pursuant to Schedule 11 during a Delivery Year, without incurring a data submission charge related to that obligation, shall share in any data submission charges paid by any other Party that has failed to satisfy said obligation during such Planning Period. Such shares shall be in proportion to the sum of the Unforced Capacity Obligations of each such Party entitled to share in the data submission charges for the most recent month.

2. In the event all of the Parties have incurred a data submission charge during a Delivery Year, those data submission charges shall be distributed as approved by the PJM Board.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 13

EMERGENCY PROCEDURE CHARGES

Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge, as set forth in Attachment DD to the PJM Tariff. The revenue associated with Emergency Procedure Charges shall be allocated in accordance with Attachment DD to the PJM Tariff.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

SCHEDULE 14

DELEGATION TO THE OFFICE OF THE INTERCONNECTION

The following responsibilities shall be delegated by the Parties to the Office of the Interconnection:

1. New Parties. With regard to the addition, withdrawal or removal of a Party the Office of the Interconnection shall:

    (a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement.

    (b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement.

2. Implementation of Reliability Assurance Agreement. With regard to the implementation of the provisions of this Agreement the Office of the Interconnection shall:

    (a) Receive all required data and forecasts from the Parties and other owners or providers of Capacity Resources;

    (b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

    (c) Monitor the compliance of each Party with its obligations under the Agreement;

    (d) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of the Agreement;

    (e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

    (f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Agreement;

(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

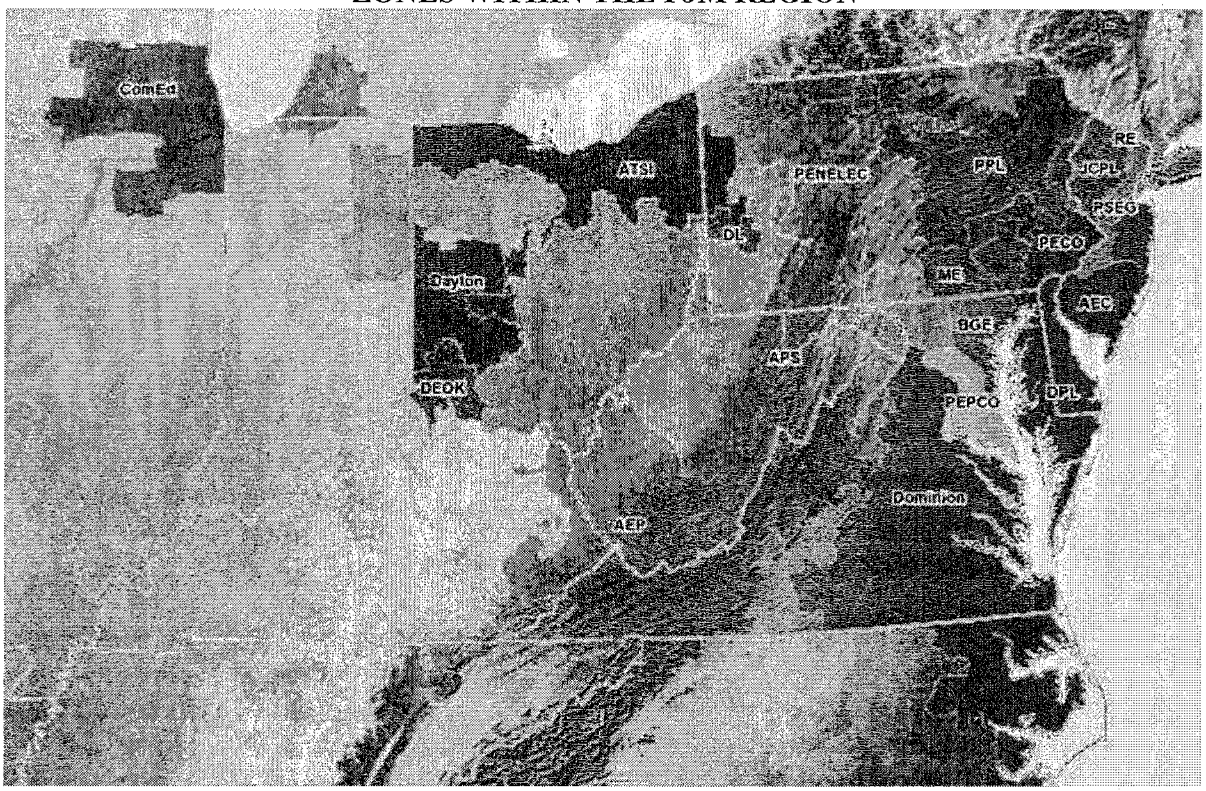
(k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Reliability Council principles, guidelines, standards, requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

SCHEDULE 15
ZONES WITHIN THE PJM REGION



FULL NAME	SHORT NAME
Pennsylvania Electric Company	Penelec
Allegheny Power	APS
PPL Group	PPL
Metropolitan Edison Company	MetEd
Jersey Central Power and Light Company	JCPL
Public Service Electric and Gas Company	PSEG
Atlantic City Electric Company	AEC
PECO Energy Company	PECO
Baltimore Gas and Electric Company	BGE
Delmarva Power and Light Company	DPL
Potomac Electric Power Company	PEPCO
Rockland Electric Company	RE
Commonwealth Edison Company	ComEd
AEP East Zone	AEP
The Dayton Power and Light Company	Dayton
Virginia Electric and Power Company	Dominion
Duquesne Light Company	DL
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK

SCHEDULE 16

Non-Retail Behind the Meter Generation Maximum Generation Emergency Obligations

1. A Non-Retail Behind The Meter Generation resource that has output that is netted from the Daily Unforced Capacity Obligation of a Party pursuant to Schedule 7 of this Agreement shall be required to operate at its full output during the first ten times between November 1 and October 31 that Maximum Generation Emergency (as defined in section 1.3.13 of Schedule 1 of the Operating Agreement) conditions occur in the zone in which the Non-Retail Behind The Meter Generation resource is located.

2. The Party for which Non-Retail Behind The Meter Generation output is netted from its Daily Unforced Capacity Obligation shall be required to report to PJM scheduled outages of the resource prior to the occurrence of such outage in accordance with the time requirements and procedures set forth in the PJM Manuals. Such Party also shall report to PJM the output of the Non-Retail Behind The Meter Generation resource during each Maximum Generation Emergency condition in which the resource is required to operate in accordance with the procedures set forth in PJM Manuals.

3. Except for failures to operate due to scheduled outages during the months of October through May, for each instance a Non-Retail Behind The Meter Generation resource fails to operate, in whole or in part, as required in paragraph 1 above, the amount of operating Non-Retail Behind The Meter Generation from such resource that is eligible for netting will be reduced pursuant to the following formula:

$$\text{Adjusted ENRBTMG} = \text{ENRBTMG} - \sum (10\% \text{ of the Not Run NRBTMG})$$

Where:

ENRBTMG equals the operating Non-Retail Behind The Meter Generation eligible for netting as determined pursuant to Schedule 7 of this Agreement.

Not Run NRBTMG is the amount in megawatts that the Non-Retail Behind The Meter Generation resource failed to produce during an occurrence of Maximum Generation Emergency conditions in which the resource was required to operate.

$\sum$ (10% of the Not Run NRBTMG) is the summation of 10% megawatt reductions associated with the events of non-performance.

The Adjusted ENRBTMG shall not be less than zero and shall be applicable for the succeeding Planning Period.

4. If a Non-Retail Behind The Meter Generation resource that is required to operate during a Maximum Generation Emergency condition is an Energy Resource and injects energy into the

Transmission System during the Maximum Generation Emergency condition, the Network Customer that owns the resource shall be compensated for such injected energy in accordance with the PJM market rules.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Retail Energy Partners LLC
AES Red Oak, LLC
Algonquin Energy Services Inc.
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, L.L.C.
Alpha Gas and Electric LLC
Ambit Northeast, LLC
Ameren Energy Marketing Company
American Electric Power Service Corporation on behalf of its affiliates:
- Appalachian Power Company
- Columbus Southern Power Company
- Indiana Michigan Power Company
- Kentucky Power Company
- Kingsport Power Company
- Ohio Power Company
- Wheeling Power Company.

American Municipal Power, Inc.
American Power Partners LLC
American PowerNet Management, L.P.
American Transmission Systems, Inc.
AP Gas and Electric (PA), LLC
APN Starfirst, LP
ArcelorMittal USA LLC
Asset and Energy Cost Saving Cooperative, LLC
Atlantic City Electric Company
Baltimore Gas and Electric Company
Bank of America, N.A.
Barclays Bank PLC
Barclays Capital Services, Inc
Bativa, IL (City of)
BBPC LLC d/b/a Great Eastern Energy
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Blue Star Energy Services, Inc.
Border Energy Electric Services, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Lavallette, New Jersey
Borough of Milltown
Borough of Mont Alto, PA

Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights, New Jersey
Borough of South River, New Jersey
BP Energy Company
Brighten Energy LLC
Cargill Power Markets LLC
Castlebridge Energy Group, LLC
CCES LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy Marketing LLC
Champion Energy, LLC
Cincinnati Bell Energy, LLC
Citizens' Electric Company of Lewisburg, PA
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Naperville
City of New Martinsville - WV
City of Philippi - West VA
City of Rochelle
Clearview Electric, Inc.
Cleveland Electric Illuminating Company (The)
Commerce Energy, Inc.
Commonwealth Edison Company
Conectiv Energy Supply, Inc.
ConEdison Energy, Inc.
ConocoPhillips Company
Consolidated Edison Solutions, Inc.
Constellation Energy Commodities Group, Inc.
Constellation NewEnergy, Inc.
Constellation Power Source Generation, Inc.
Corporate Services Support Corp
Credit Suisse (USA), Inc.
Dayton Power & Light Company (The)
DC Energy LLC
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy LLC
Direct Energy Business, LLC
Direct Energy Services, LLC
Discount Energy Group, LLC
Discount Energy, LLC
Dominion Retail, Inc.

Downes Associates, Inc.
DPL Energy Resources, Inc.
Driftwood LLC
DTE Energy Supply, Inc.
DTE Energy Trading, Inc.
Duke Energy Commercial Asset Management, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Retail Sales, LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Dynegy Energy Services, Inc.
Dynegy Kendall Energy, LLC
E Minus LLC
Eagle Energy, LLC
Easton Utilities Commission
EDF Industrial Power Services (IL), LLC
EDF Trading North America, LLC
Edison Mission Marketing and Trading, Inc.
Employers' Energy Alliance of Pennsylvania, Inc.
Energetix, Inc.
Energy America, LLC
Energy Cooperative Association of Pennsylvania (The)
Energy Cooperative of America, Inc.
Energy International Power Marketing Corporation
Energy Plus Holdings LLC
Energy Services Providers, Inc.
EnerPenn USA, LLC
ERA MA, LLC
Evraz Claymont Steel
Exelon Energy Company
Exelon Generation Co., LLC
FirstEnergy Solutions Corp.
First Point Power, LLC
Front Royal (Town of)
Galt Power Inc.
Gateway Energy Services Corporation
GenOn Power Midwest, LP
Gerdau Ameristeel Energy, Inc.
GDF Suez Retail Energy Solutions, LLC
Glacial Energy of New Jersey, Inc.
Great American Power, LLC
Green Mountain Energy Company
Hagerstown Light Department
Harrison REA, Inc. - Clarksburg, WV
Hess Corporation

HIKO Energy, LLC
Hoosier Energy REC, Inc.
HOP Energy, LLC
HSBC Technology & Services (USA), Inc.
Hudson Energy Services, LLC
IDT Energy, Inc.
Illinois Municipal Electric Agency
J. Aron & Company
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jersey Central Power & Light Company
Kuehne Chemical Company, Inc.
L & P Electric Inc., d/b/a Leggett & Platt Electric Inc.
Liberty Power Corp., L.L.C.
Liberty Power Delaware LLC
Liberty Power Holdings LLC
Linde Energy Services, Inc.
Lower Electric, LLC
Macquarie Cook Energy LLC
Major Energy Electric Services LLC
Manitou Energy Fund, LP
Marathon Power, LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm II LLC
Meadow Lake Wind Farm III LLC
Meadow Lake Wind Farm IV LLC
Meadow Lake Wind Farm LLC
MeadWestvaco Corporation
Metropolitan Edison Company
MidAmerican Energy Company
Mint Energy, LLC
Morgan Stanley Capital Group, Inc.
MP2 Energy NE, LLC
MXenergy Electric, Inc.
Natgasco, Inc.
Nexgen Management and Consulting Inc
Nextera Energy Services New Jersey, LLC
Nextera Energy Services, Illinois, LLC
Noble Americas Energy Solutions LLC
Noble Americas Gas & Power Corp.
Nordic Energy Services LLC
North American Power and Gas LLC.
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northern Virginia Electric Cooperative – NOVEC
Northeastern REMC

NRG Power Marketing, L.L.C.
NYSEG Solutions, Inc.
Oasis Power, LLC dba Oasis Energy
Occidental Power Services, Inc.
Ohio Edison Company
Ohms Energy Company, LLC
Old Dominion Electric Cooperative
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power OH, LLC
Palmco Power PA, LLC
Panda Power Corporation
Parma Energy, LLC
PBF Power Marketing LLC
PECO Energy Company
Pennsylvania Electric Company
Pennsylvania Power Company
People's Power & Gas, LLC
PEPCO Energy Services, Inc.
Planet Energy (Maryland) Corp.
Planet Energy (Pennsylvania) Corp.
Planet Energy (USA) Corp.
Plymouth Rock Energy, LLC
Potomac Electric Power Company
Powhatan Energy Fund LLC
PPL Electric Utilities Corporation d/b/a PPL Utilities
PPL Energy Plus, LLC
Prairieland Energy, Inc.
PSEG Energy Resources and Trade LLC
Public Power, LLC
Public Service Electric & Gas Company
Realgy, LLC
ResCom Energy, LLC
Respond Power LLC
RG Steel Sparrows Point, LLC
Riverside Generating, LLC
Rolling Hills Generating, LLC
S.J. Energy Partners, Inc.
Santanna Energy Services
SMART Papers Holdings, LLC
Solios Power Mid-Atlantic Trading LLC
South Jersey Energy Company
South Jersey Energy Solutions, L.L.C.
Southeastern Power Administration
Southern Indiana Gas & Electric
Southern Maryland Electric Cooperative, Inc.

Spark Energy, L.P.
Sperian Energy Corp
Starion Energy PA Inc.
Stream Energy Columbia, LLC
Stream Energy Maryland, LLC
Stream Energy Pennsylvania, LLC
Superior Plus Energy Services Inc.
Sustainable Star, LLC
TC Energy Trading, LLC
Tenaska Power Services Co.
TERM Power & Gas, LLC
Texas Retail Energy, LLC
The Trustees of the University of Pennsylvania
Thurmont Municipal Light Company
Toledo Edison Company (The)
Town of Berlin, Maryland
Town of Williamsport
TransAlta Energy Marketing (U.S.) Inc.
TransCanada Power Marketing Ltd.
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trinity Powerworks, Inc.
U.S. Energy Partners dba PAETEC Energy Marketing
UBS AG, acting through its London Branch
UGI Energy Services, Inc.
UGI Utilities, Inc. - Electric Division
Valero Power Marketing, LLC
VCharge, Inc.
Verde Energy USA, Inc.
Verde Energy USA Illinois, LLC
Vineland Municipal Electric Utility (City of Vineland)
Virginia Electric & Power Company
Viridian Energy PA LLC
Wabash Valley Power Association, Inc.
Washington Gas Energy Services, Inc.
Wellsboro Electric Company
West Penn Power Company d/b/a Allegheny Power
Xoom Energy, LLC
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
York Generation Company, LLC

Exhibit KMM-16

Exhibit KMM-16

2011 TCRR Filing - Excluding Prior Year Under/(Over) Collection - Merged Rates

Columbus Southern Power Company

Class	kWh	Full TCRR	Cents/kWh	Basic Transmission	Difference $	Cents/kWh	
Residential	7,478,966,469	72,260,510.49	0.96618	49,391,513.92	22,868,996.57	0.30578	
Commercial	5,298,662,205	42,437,247.77	0.8009	26,955,001.05	15,482,246.72	0.29219	0.29225
Industrial	2,991,640,875	22,180,057.84	0.7414	13,745,229.29	8,434,828.56	0.28195	0.27859
Joint Service Territory	1,416,000,000	7,390,782.30	0.52195	3,546,342.30	3,844,440.00	0.2715	
Other	56,637,859	270,621.47	0.47781	102,124.95	168,496.52	0.2975	
Total	17,241,907,407	144,539,219.88	0.8383	93,740,211.51	50,799,008.37	0.29463	
RS	7,468,234,369	72,225,294.59	0.9671	49,388,180.71	22,837,113.88	0.30579	
GS1	267,107,733	2,474,566.17	0.92643	1,676,742.08	797,824.09	0.29869	
GS2 Sec	1,070,771,912	10,690,325.07	0.99838	7,651,367.30	3,038,957.76	0.28381	
GS2-TOD/LM *	8,407,793	85,138.99	1.01262	61,276.84	23,862.16	0.28381	
GS2 Pri	41,425,516	509,457.73	1.22982	395,964.24	113,493.49	0.27397	
GS3 Sec	2,949,863,389	23,858,697.11	0.80881	14,992,882.69	8,865,814.42	0.30055	
GS3-TOD/LM	3,935,298	29,785.48	0.75688	17,957.94	11,827.54	0.30055	
GS3 Pri	1,824,845,901	12,869,225.09	0.70522	7,574,799.68	5,294,425.41	0.29013	
GS4/IRP	3,511,856,491	21,454,789.63	0.61092	11,920,099.25	9,534,690.37	0.2715	
SL	42,622,935	139,803.23	0.328	13,170.49	126,632.74	0.2971	
AL	40,682,159	133,437.48	0.328	12,570.79	120,866.70	0.2971	
SBS-Sub/Tran-Maint & Backup	12,153,910	68,699.31	0.56524	35,199.49	33,499.82	0.27563	
Total	17,241,907,407	144,539,219.88	0.8383	93,740,211.51	50,799,008.37	0.29463	

Ohio Power Company

Class	kWh	Full TCRR	Cents/kWh	Basic Transmission	Difference $	Cents/kWh	
Residential	7,355,589,587	71,046,684.24	0.96589	48,555,240.43	22,491,443.81	0.30577	
Commercial	5,572,233,514	47,913,741.98	0.85987	31,677,620.42	16,236,121.56	0.29138	0.29145
Industrial	11,646,481,377	77,344,378.16	0.6641	45,013,934.33	32,330,443.83	0.2776	0.27694
Joint Service Territory	1,416,000,000	7,384,526.87	0.52151	3,540,086.87	3,844,440.00	0.2715	
Other	76,056,194	303,360.42	0.39886	77,552.05	225,808.36	0.2969	
Munis	6,921,718	48,847.56	0.70571	28,840.35	20,007.21	0.28905	
Total	26,073,282,390	204,041,539.22	0.78257	128,893,274.45	75,148,264.77	0.28822	
RS	7,341,631,895	71,000,922.05	0.9671	48,550,945.88	22,449,976.17	0.30579	
GS1	368,481,455	3,413,722.75	0.92643	2,313,105.49	1,100,617.26	0.29869	
GS2 Sec	2,659,932,873	27,049,458.22	1.01692	19,500,302.74	7,549,155.49	0.28381	
GS2 RL - GS - TOD	112,792,413	1,142,158.53	1.01262	822,042.38	320,116.15	0.28381	
GS2 Pri	428,726,382	4,249,475.41	0.99119	3,074,893.73	1,174,581.67	0.27397	
GS2 Sub/Trans	284,625,494	2,606,525.36	0.91577	1,844,668.30	761,857.06	0.26767	
GS3 Sec	2,689,495,833	20,415,856.20	0.7591	12,332,576.48	8,083,279.73	0.30055	
GS3 Pri	2,545,329,718	17,668,539.26	0.69416	10,283,774.15	7,384,765.11	0.29013	
GS3 Sub/Trans	849,980,139	5,852,047.27	0.68849	3,442,693.57	2,409,353.70	0.28346	
GS4 Pri	266,471,873	1,621,576.39	0.60854	881,051.06	740,525.34	0.2779	
GS4/IRP Sub/Trans	8,336,829,904	48,136,995.26	0.5774	25,502,502.07	22,634,493.19	0.2715	
EHG	22,324,423	184,723.43	0.82745	125,963.32	58,760.11	0.26321	
SS	41,967,228	224,860.41	0.5358	114,394.27	110,466.14	0.26322	
EHS	426,575	2,285.59	0.5358	1,162.76	1,122.83	0.26322	
OL	57,443,356	188,414.21	0.328	17,750.00	170,664.21	0.2971	
SL	66,822,827	219,178.87	0.328	20,648.25	198,530.62	0.2971	
SBS-Sub/Tran-Backup	0	64,800.00	0.56524	64,800.00	0.00	0.56524	
Total	26,073,282,390	204,041,539.22	0.78257	128,893,274.45	75,148,264.77	0.28822	

AEP Ohio

RS	14,809,866,264	143,226,216.64	0.9671	97,939,126.59	45,287,090.05	0.30579
GS1	635,589,189	5,888,288.92	0.92643	3,989,847.57	1,898,441.35	0.29869
GS2 Sec	3,730,704,785	37,739,783.29	1.0116	27,151,670.04	10,588,113.25	0.28381
GS2-TOD/LM /RL - GS - TOD	121,200,206	1,227,297.52	1.01262	883,319.22	343,978.30	0.28381
GS2 Pri	470,151,899	4,758,933.13	1.01221	3,470,857.98	1,288,075.16	0.27397
GS2 Sub/Trans	284,625,494	2,606,525.36	0.91577	1,844,668.30	761,857.06	0.26767
GS3 Sec	5,639,359,222	44,274,553.31	0.7851	27,325,459.17	16,949,094.14	0.30055
GS3-TOD/LM	3,935,298	29,785.48	0.75688	17,957.94	11,827.54	0.30055
GS3 Pri	4,370,175,619	30,537,764.35	0.69878	17,858,573.83	12,679,190.52	0.29013
GS3 Sub/Trans	849,980,139	5,852,047.27	0.68849	3,442,693.57	2,409,353.70	0.28346
GS4 Pri	266,471,873	1,621,576.39	0.60854	881,051.06	740,525.34	0.2779
GS4/IRP Sub/Trans	11,848,686,396	69,591,784.88	0.58734	37,422,601.32	32,169,183.56	0.2715
EHG	22,324,423	184,723.43	0.82745	125,963.32	58,760.11	0.26321
SS	41,967,228	224,860.41	0.5358	114,394.27	110,466.14	0.26322
EHS	426,575	2,285.59	0.5358	1,162.76	1,122.83	0.26322
SBS-Sub/Tran-Backup	12,153,910	133,499.31	1.09841	99,999.49	33,499.82	0.27563
OL	98,125,516	321,851.69	0.328	30,320.78	291,530.91	0.2971
SL	109,445,762	358,982.10	0.328	33,818.74	325,163.36	0.2971
Total	43,315,189,797	348,580,759.10	0.80475	222,633,485.96	125,947,273.14	0.29077
Residential	14,834,556,056	143,307,194.73	0.96604	97,946,754.35	45,360,440.38	0.30578
Commercial	11,010,511,489	90,973,819.20	0.82625	58,841,138.83	32,132,680.38	0.29184
Industrial	17,470,122,252	114,299,745.17	0.65426	65,845,592.79	48,454,152.38	0.27735
Total	43,315,189,798	348,580,759.10	0.80475	222,633,485.96	125,947,273.14	0.29077

Basic Transmission includes only NITS, Transmission Enhancement Charges, Point-to-Point Revenues and TA Phase-In Credits

Exhibit KMM-17

Exhibit KMM- 17

Competitive Bid Auction Schedule Approved in Case 10-388-EI-SSO

Procurement Date	Tranches Procured	Delivery Periods			
		11-Jun	12-Jun	13-Jun	14-Jun
Oct-10	17	12 month June 2011 to May 2012			
	17	24 month June 2011 to May 2013			
	16	36 month June 2011 to May 2014			
Jan-11	17	12 month June 2011 to May 2012			
	17	24 month June 2011 to May 2013			
	16	36 month June 2011 to May 2014			
Oct-11	17		2 year June 2012 to May 2014		
Jan-12	17		2 year June 2012 to May 2014		
Oct-12	17			1 year June 2013 to May 2014	
Jan-13	17			1 year June 2013 to May 2014	

Exhibit KMM-18

OhioEdison
A FirstEnergy Company

Ohio Edison utility customers save 6% off electric generation

Lock in guaranteed savings of 6% off your electric generation price through your June 2014 meter read.

You can enroll now if:

1. You are a residential customer of Ohio Edison Company and
2. You have a copy of your electric bill.

Enroll online

3 easy steps and you are on your way.

Enroll Now

Enroll by Phone

Prefer to enroll by phone?

Call us at 1-888-254-6359.

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Online-Only: Special Savings Offer for Duke Energy Customers

Qualifying customers can save on this low fixed rate of 5.65¢ per kWh for generation service through March 2013.

point-by-point comparison

Compare	Duke Energy*	FirstEnergy Solutions
RS Rate per kWh:	6.03¢	5.65¢
% savings:	None	6% savings

Click here for our Two Year Offer!

You can enroll now if:

1. You are a Duke Energy residential customer
2. You have a copy of your electric bill

Enroll online

Three simple steps and you are on your way.

Enroll Now

Enroll by Phone

Prefer to enroll by phone?
Call us at 1-877-204-9520.

*The chart above shows the average generation rate (for typical Duke Energy RS customers using less than 9,999 kWh/year) as of February 8, 2012 as published on Duke energy's website. Savings are estimated based on an average customer (using 9,999 kWh a year) over a contract beginnng in March 2012 through March 2014 and will vary according to usage, term length of signed contract and market conditions. Please call 1-866-430-4408 to find your savings. FirstEnergy Solutions is an unregulated subsidiary of FirstEnergy Corp., and an affiliate of Ohio Edison, Toledo Edison and The Illuminating Company.

Questions on your enrollment? Please call us at 1-877-204-9520.

FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC are unregulated subsidiaries of FirstEnergy Corp. Neither FirstEnergy Solutions Corp. nor Allegheny Energy Supply Company, LLC are the same company as FirstEnergy Corp. The prices of FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC are not regulated by the state public utility commissions. You do not have to buy electricity from FirstEnergy Solutions Corp. or Allegheny Energy Supply Company LLC in order to receive the same quality regulated services from FirstEnergy Corp.'s regulated electric utilities - Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, West Penn Power Company, Pennsylvania Power Company, Pennsylvania Electric Company, Metropolitan Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, The Potomac Edison Company, and American Transmission Systems, Incorporated.

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Electricity Rates and Plans for the Duke Energy Ohio (Duke) Service Area

Direct Energy's electricity rates are valid Cincinnati, Dayton, Fairfield, Hamilton, Lebanon and the surrounding area. View and compare our electricity rates in the table below to find the best electricity plan.

SHARE

Plan Description	Rate/kWh	Term	Cancellation Fee	Ready to Sign-Up?
Price Protection Plan - 1 year More Info	**5.99¢**	12 months	No fees	Sign Up Now
Price Protection Plan - 1 Year Special Military Offer! More Info	**5.69¢**	12 months	No fees	Sign Up Now
Price Protection Plan - 1 Year Special Senior Citizen Offer! More Info	**5.69¢**	12 months	No fees	Sign Up Now

Helping you compare electricity rates to find the best plan!

Direct Energy wants to be your electricity provider! We provide a range of electricity plans to fit your energy needs. View more information on our great electricity plans in the table above.

Have a question? Need more information before you sign up?

- Call us at **1-888-566-9988**

Get your energy from the best electricity provider in the Duke Energy Ohio (Duke) service area

Direct Energy, a leading North American electricity and gas provider, offers you a great electricity plan option in the Duke Energy Ohio (Duke) service area including:

- Aberdeen
- Addyston
- Amelia
- Batavia
- Bethel
- Blanchester
- Branch Hill
- Camp Dennison
- Chilo
- Cincinnati
- Clarksville
- Cleves
- College Corner
- Collinsville
- Dayton
- Edenton
- Fairfield
- Fayetteville
- Feesburg
- Felicity
- Franklin
- Georgetown
- Germantown
- Goshen
- Hamersville
- Hamilton
- Harrison
- Higginsport
- Hooven
- Kings Mills
- Lebanon
- Loveland
- Lynchburg
- Maineville
- Marathon
- Mason
- Miamisburg
- Miamitown
- Miamiville
- Middletown
- Midland
- Milford
- Monroe
- Morrow
- Moscow
- Mount Orab
- Neville
- New Richmond
- Newtonsville
- North Bend
- Okeana
- Oregonia
- Overpeck
- Owensville
- Oxford
- Pleasant Plain
- Pt Pleasant
- Reily
- Ripley
- Ross
- Russellville
- Sardinia
- Seven Mile
- Shandon
- Somerville
- South Lebanon
- Springboro
- St Martin
- Terrace Park
- Trenton
- Waynesville
- West Chester
- West Elkton
- Williamsburg
- Winchester
- and more.

Did you know that the term kWh stands for kilowatt hour, the standard unit of measure for electricity *consumption. One kWh is equivalent to 1000 watt hours or 3.6 megajoules.*

Natural Gas & Electricity Provider in Ohio

Ohio Natural Gas Rates / Prices

Electricity Prices in Cincinnati, Dayton, Fairfield, Hamilton, Lebanon and Area

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Exhibit KMM-19

Exhibit KMM-19

ADMINISTRATIVELY ESTIMATED MARKET PRICES

Using $355.72/mw-day for capacity	OH Res				OH Com				OH Ind			
	PY 12/13	PY 13/14	PY 14/15	PY 15/16	PY 12/13	PY 13/14	PY 14/15	PY 15/16	PY 12/13	PY 13/14	PY 14/15	PY 15/16
ATC Simple Swap	32.68	35.34	37.75	39.91	32.68	35.34	37.75	39.91	32.68	35.34	37.75	39.91
Basis	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Load Shape and Following	6.12	6.35	6.57	6.71	2.54	2.68	2.79	2.91	1.91	1.90	1.99	2.12
Retail Administration	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Alt. Energy Req.	0.55	0.71	0.92	1.20	0.54	0.71	0.91	1.19	0.54	0.71	0.92	1.20
Ancillaries	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Losses	2.52	2.71	2.87	3.01	1.44	1.55	1.65	1.74	0.64	0.69	0.73	0.77
Capacity	30.01	28.64	28.83	28.78	23.01	21.90	22.45	22.49	17.29	15.57	15.82	15.84
ARR Credit	(1.54)	(1.44)	(1.46)	(1.46)	(1.11)	(1.04)	(1.08)	(1.08)	(0.97)	(0.89)	(0.92)	(0.89)
Transaction Risk Adder	3.83	3.93	4.09	4.22	3.27	3.37	3.54	3.68	2.92	2.98	3.13	3.26
Total	80.53	82.59	85.90	88.71	68.73	70.86	74.35	77.18	61.36	62.64	65.75	68.56

Using $255/mw-day for capacity	OH Res				OH Com				OH Ind			
	PY 12/13	PY 13/14	PY 14/15	PY 15/16	PY 12/13	PY 13/14	PY 14/15	PY 15/16	PY 12/13	PY 13/14	PY 14/15	PY 15/16
ATC Simple Swap	32.68	35.34	37.75	39.91	32.68	35.34	37.75	39.91	32.68	35.34	37.75	39.91
Basis	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Load Shape and Following	4.94	5.24	5.48	5.67	2.19	2.37	2.48	2.62	1.64	1.67	1.77	1.91
Retail Administration	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Alt. Energy Req.	0.55	0.71	0.92	1.20	0.54	0.71	0.91	1.19	0.54	0.71	0.92	1.20
Ancillaries	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Losses	2.45	2.63	2.80	2.95	1.43	1.54	1.64	1.73	0.63	0.68	0.73	0.77
Capacity	21.52	20.53	20.67	20.63	16.49	15.70	16.09	16.12	12.39	11.16	11.34	11.35
ARR Credit	(1.54)	(1.44)	(1.46)	(1.46)	(1.11)	(1.04)	(1.08)	(1.08)	(0.97)	(0.89)	(0.92)	(0.89)
Transaction Risk Adder	3.35	3.47	3.62	3.76	2.93	3.05	3.21	3.34	2.66	2.75	2.90	3.03
Total	70.28	72.83	76.12	79.00	61.50	64.00	67.34	70.18	55.93	57.77	60.82	63.62

Using $145.79/mw-day for capacity	OH Res				OH Com				OH Ind			
	PY 12/13	PY 13/14	PY 14/15	PY 15/16	PY 12/13	PY 13/14	PY 14/15	PY 15/16	PY 12/13	PY 13/14	PY 14/15	PY 15/16
ATC Simple Swap	32.68	35.34	37.75	39.91	32.68	35.34	37.75	39.91	32.68	35.34	37.75	39.91
Basis	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Load Shape and Following	3.67	4.10	4.39	4.64	1.82	2.06	2.19	2.33	1.35	1.45	1.56	1.70
Retail Administration	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Alt. Energy Req.	0.55	0.71	0.92	1.20	0.54	0.71	0.91	1.19	0.54	0.71	0.92	1.20
Ancillaries	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Losses	2.37	2.56	2.73	2.88	1.42	1.53	1.63	1.72	0.63	0.68	0.72	0.76
Capacity	12.30	11.74	11.82	11.79	9.43	8.98	9.20	9.22	7.09	6.38	6.48	6.49
ARR Credit	(1.54)	(1.44)	(1.46)	(1.46)	(1.11)	(1.04)	(1.08)	(1.08)	(0.97)	(0.89)	(0.92)	(0.89)
Transaction Risk Adder	2.82	2.97	3.12	3.27	2.56	2.70	2.85	2.98	2.38	2.50	2.64	2.78
Total	59.19	62.33	65.61	68.57	53.69	56.61	59.78	62.62	50.05	52.52	55.49	58.30

Using $RPM/mw-day for capacity	OH Res				OH Com				OH Ind			
	2012	2013/May 14	PY 14/15	PY 15/16	2012	2013/May 14	PY 14/15	PY 15/16	2012	2013/May 14	PY 14/15	PY 15/16
ATC Simple Swap	32.68	35.34	37.75	39.91	32.68	35.34	37.75	39.91	32.68	35.34	37.75	39.91
Basis	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Load Shape and Following	3.67	4.10	4.39	4.64	1.82	2.06	2.19	2.33	1.35	1.45	1.56	1.70
Retail Administration	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Alt. Energy Req.	0.55	0.71	0.92	1.20	0.54	0.71	0.91	1.19	0.54	0.71	0.92	1.20
Ancillaries	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Losses	2.37	2.56	2.73	2.88	1.42	1.53	1.63	1.72	0.63	0.68	0.72	0.76
Capacity (1)(2)	5.78	2.33	12.11	12.11	4.74	1.85	9.40	9.40	3.19	1.35	7.17	7.17
ARR Credit	(1.54)	(1.44)	(1.46)	(1.46)	(1.11)	(1.04)	(1.08)	(1.08)	(0.97)	(0.89)	(0.92)	(0.89)
Transaction Risk Adder	2.82	2.97	3.12	3.27	2.56	2.70	2.85	2.98	2.38	2.50	2.64	2.78
Total	52.67	52.92	65.90	68.89	53.69	56.61	59.98	62.80	50.05	52.52	56.18	58.98

Weighted average 2014/2015	60.22
Weighted average 2015/2016	63.46
Weighted average 2014/2015 w/ $255 capacity	67.34

(1)Since the RPM capacity prices will not be known until May 2012, prior delivery year capacity prices were utilized for the 2015/2016 delivery year.
(2) From Laura Thomas testimony in support of stipulation, Exhibit LJT-1, page 2 of 3.

Exhibit KMM-20

Exhibit KMM- 20

Ohio Power Company

ESP

Prices are $ per MWH

	Generation Service Price	June 2012- May 2013	June 2013- May 2014	June 2014- December 2014	January 2015- May 2015	June 2015- May 2016
1	Standard Offer Base Generation Rate (2012 Rates) (A)	22.50	22.50	22.50	0.00	0.00
2	Fuel Adjustment Clause Rider (2012 Estimate) (A)(G)	36.10	36.10	36.10	67.34	63.46
3	Transmission Adjustment (B)	2.91	2.91	2.91	0.00	0.00
4	Enhanced Service Reliability Rider (B)	0.71	0.71	0.71	0.71	0.71
5	gridSMART® Rider (B)	0.13	0.13	0.13	0.13	0.13
6	Generation Resource Rider (D)	0.00	0.05	0.11	0.15	0.22
7	Retail Stability Rider (A)	2.00	2.00	2.00	2.00	0.00
8	Alternative Energy Rider	Unknown	Unknown	Unknown	Unknown	Unknown
9	Distribution Investment Rider (E)	1.96	2.36	2.60	2.60	0.00
10	Storm Damage Recovery Mechanism	Unknown	Unknown	Unknown	Unknown	Unknown
11	Pool Termination or Modification Provision	Unknown	Unknown	Unknown	Unknown	Unknown
12		66.32	66.76	67.07	72.94	64.53

MRO

	Current ESP Full Fuel					
13	Standard Offer Generation Service (2012 Rate) (B)	21.00	21.00	21.00	21.00	21.00
14	Environmental Rider	0.16	0.16	0.16	0.16	0.16
15	Fuel Adjustment Clause Rider (2012 Rate) (A)	36.10	36.10	36.10	36.10	36.10
16	Transmission Adjustment (A)	2.91	2.91	2.91	2.91	2.91
17		60.17	60.17	60.17	60.17	60.17
18		90%	80%	70%	60%	50%
19		54.15	48.14	42.12	36.10	30.09
20	Market Rate Offer	44.76	44.76	57.34	57.34	63.46
21	Alternative Energy Requirement (F)	0.54	0.71	0.92	0.92	1.28
22		45.30	45.47	58.26	58.26	64.74
23		10%	20%	30%	40%	50%
24		4.53	9.09	17.48	23.30	32.37
25	Weighted MRO	58.68	57.23	59.60	59.41	62.46
26	**ESP Benefit**	-7.64	-9.53	-7.47	-13.53	-2.08

Source
(A) Exhibit DMR-1. Current FAC includes alternative energy requirements.
(B) David M. Roush Work Papers
(B) Exhibit AEM-2
(D) Supplemental Testimony of Philip J. Nelson Exhibit PJN-5 page 2
Annual revenue requirement delayed to June, 2013.
(E) William A. Allen Direct Testimony
(F) Exhibit LJT-2
(G) Jan2015 through May 2016 values from Exhibit KMM-

Exhibit KMM-21

Exhibit KMM-21

Cost of above market capacity, GRR and RSR

GWh of Load Served

CRES Load Served at $146/MW-d	PY12/13	PY13/14	6/14-12/14	1/15-5/15	PY14/15
Residential	4,844	5,100	3,425	2,472	5,897
Commercial	4,099	5,041	3,577	2,343	5,920
Industrial	4,846	6,801	4,655	3,278	7,933
Total	13,789	16,942	11,658	8,093	19,750
CRES Load Served at $255/MW-d	**PY12/13**	**PY13/14**	**6/14-12/14**	**1/15-5/15**	**PY14/15**
Residential	3,175	4,318	2,005	1,447	3,452
Commercial	6,307	6,403	3,351	2,191	5,542
Industrial	6,974	6,769	3,298	2,334	5,632
Total	16,456	17,490	8,655	5,971	14,626
SSO Load Served by AEP Ohio	**PY12/13**	**PY13/14**	**6/14-12/14**	**1/15-5/15**	**PY14/15**
Residential	6,598	5,071	2,924		2,924
Commercial	3,911	2,973	1,797		1,797
Industrial	7,442	5,785	3,400		3,400
Total	17,950	13,829	8,121		8,121
SSO Load Served by Auction at $255/MW-d	**PY12/13**	**PY13/14**	**6/14-12/14**	**1/15-5/15**	**PY14/15**
Residential	-	-	-	2,110	2,110
Commercial	-	-	-	1,181	1,181
Industrial	-	-	-	2,383	2,383
Total	-	-	-	5,674	5,674
Total Connected Load	**PY12/13**	**PY13/14**	**6/14-12/14**	**1/15-5/15**	**PY14/15**
Residential	14,616	14,489	8,354	6,029	14,384
Commercial	14,317	14,417	8,726	5,714	14,440
Industrial	19,262	19,355	11,354	7,994	19,348
Total	48,195	48,261	28,434	19,738	48,172

RPM Based Capacity $/MWH (1)					
Residential	$2.33	$2.33	$12.11	$12.11	
Commercial	$1.85	$1.85	$9.40	$9.40	
Industrial	$1.35	$1.35	$7.17	$7.17	
					Total
Capacity Revenues based upon RPM (000)	$53,892	$61,435	$187,919	$130,310	$433,555
Capacity Revenues Exhibit WAA-4 page 1of 2 (000)	$391,000	$413,000	$233,333	$166,667	$1,204,000
RSR Revenues from Shopping Customers (000) (2)	$60,489	$68,864	$40,625	$28,128	$198,106
GGR Revenues from non Shopping Customers (000) (3)	-	$691	$893	$851	$2,436

(1) Exhibit LJT-1 in support of stipulation
Used 1/13 to 5/14 values for 2012 to be conservative
(2) Shopping volumes multiplied by RSR Rate
(3) Non shopping volumes multiplied by GRR Rate

Exhibit KMM-22

OHIO POWER COMPANY'S RESPONSES
TO IEU-OHIO'S DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
FIRST SET

INTERROGATORY

IEU-1-003 If AEP-Ohio conducts a limited energy-only slice of system SSO auction for 5% of the SSO load, as discussed in the direct testimony of Robert P. Powers, what other charges would customers receiving SSO service be required to pay? Please provide this information by year, rate schedule, unit charge and dollars.

RESPONSE

The rates for customers would include the purchased power expense for 5% of the SSO load in the FAC. Charges for base generation, transmission and distribution service would be at the then current AEP Ohio rates.

For the available information by rate schedule, unit charge and dollars, see the Company's filed Testimony, Exhibits and Workpapers. No calculations have been performed since the results of such auction are not known.

OHIO POWER COMPANY'S RESPONSES
TO IEU-OHIO'S DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
FIRST SET

INTERROGATORY

IEU-1-004 Has AEP-Ohio performed any studies or analysis to unbundle its proposed SSO rates into energy and non-energy components in order to conduct a limited energy-only slice of system SSO auction for 5% of the SSO load?

RESPONSE

No such studies or analysis have been performed.

Prepared by: D. Roush

Exhibit KMM-23

AMERICAN ELECTRIC POWER

Date: November 4, 2011

To: File

From: Michael Baird and Paul Pennino

Subject: ASC 360 - Cross-State Air Pollution Rule: Recoverability Test – East Fleet

I. Background

On July 6, 2011, the US Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR) which is to be implemented by January 2012. This rule replaces EPA's 2005 Clean Air Interstate Rule. The rule provides much less flexibility and fails to consider improvements in air quality that have occurred under the Clean Air Interstate Rule (CAIR), which it will replace. AEP is evaluating several compliance options to meet the emissions limits established by the CSAPR. There are numerous unresolved questions associated with the impacts of the CSAPR on the PJM system.

II. ASC 360 – Property, Plant and Equipment

A. When to Test a Long-Lived Asset for Recoverability – Triggering Event

ASC 360-10-35-21 states:

> A long-lived asset (asset group) shall be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. The following are examples of such events or changes in circumstances:

- a. A significant decrease in the market price of a long-lived asset (asset group)
  - Not applicable.
- b. A significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used or in its physical condition
  - Not applicable.
- c. A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset (asset group), including an adverse action or assessment by a regulator.
  - Met.
    - Legal Factors: The implementation of the CSAPR could have a significant adverse affect on the East Fleet.

- d. An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset (asset group).
    - Not applicable.

- e. A current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group)

    - Not met. The units are reviewed for recoverability purposes at the East Company generation only level, where there is no issue.

- f. A current expectation that, more likely than not, a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. The term *more likely than not* refers to a level of likelihood that is more than 50 percent.

    - Not met. There is no current expectation that, more likely than not, any of the units will be sold or otherwise disposed of significantly before the end of its previously estimated life.

Conclusion

Since a trigger has been met, a test for recoverability will be performed.

As cost-based rate regulated entities, APCo, KYPCo and I&M file rate cases to recover their incurred costs and as such any net cash flow projections presume the fact that costs will be fully recovered over the life of the assets. These cost-based regulated units will be included in the asset group (discussed below) and in accordance with ASC 360, any potential impairment for the APCo, KYPCo or I&M units will be evaluated if and when there is notification of potential disallowance by state regulators as provided under ASC 980 - Regulated Operations.

Since the Ohio companies generation assets are not cost-based rate regulated and do not fall under ASC 980 Regulated Operations, a recoverability test for these generating assets should be performed to determine if gross cash flows from the asset group are sufficient to recover the book value of the asset group as required under ASC 360. A discounted cash flow impairment test is necessary only if the gross cash flows fail to recover the book cost of the asset.

B. Held and Used Requirement: Test for Recoverability using Gross Cash Flows

East Pool

It is appropriate to use the East Pool as the lowest level of identifiable cash flows as described below. No other alternative courses of action to recover the carrying amount of the asset group were considered since the all of the assets are included in the East Pool.

Asset Group

An asset group is the unit of accounting for a long-lived asset or assets to be held and used, which represents the lowest level for which identifiable cash flows are largely independent of the cash flows of other groups of assets and liabilities.

In determining how to group assets at the lowest level for which there are identifiable cash flows that are largely independent of cash flows from other assets groups, we considered whether to include generation, transmission and distribution assets all in one entity level group or use the generation assets as a stand-alone asset group. Also, we considered whether to include all East operating companies together in one asset group versus just the assets of a stand-alone operating company. We considered all of the East company generation assets as the lowest level.

The non-cost based rate generation assets are not operated separately, but are coordinated and dispatched with the generation assets owned by the other East cost-based regulated operating companies (APCo, KYPCo and I&M). The costs and benefits of the generation assets are shared among all of the East operating companies in the Interconnection Agreement (Agreement). The output of the Ohio Companies' generation plants is available to fulfill the continuing native load obligations of those jurisdictions through the Power Pool Agreements. Due to the nature of electrical energy and the operation of the plants through the Pool, it is impossible to match cash inflows from the sales to cash outflows from either purchased or generated power by unit or by plant.

Based on the above considerations, the generation function group including all East companies that are part of the Agreement, is the lowest level where cash flows can be identified and are largely independent of other assets and thus is the asset group to be used in the recoverability test.

<u>Cash Flow</u>
Since we do not have cash flow statements by function, nor do we forecast by function, we used the attached 2011 Preliminary Long Range Plan to develop the required cash flow. The forecast reflects the capital expenditures necessary to extend the service potential of certain assets. This is inconsistent with the recoverability cash flow analysis required in ASC 360, which calls for cash flows to be based on the existing service potential of the assets at the date they are tested. To compensate for this we deducted the cash flows used for investing activities from the operating cash flows and used the resulting net cash flows to reflect the estimated cash flows achieved from the units existing service potential.

The forecast we used was for 10 years. The forecast model does not project past the 10 year period. We used the year 2020 net cash flows to estimate an additional 20 years cash flow. The use of the 2020 net cash flows was used because these cash flows are believed to be the best estimate of the forecasted cash flows due to the inclusion of significant capital expenditures to comply with environmental requirements which extends the useful lives beyond the current depreciable lives. The current average depreciable life of the Least Exposed units is 23 years; however, the model includes significant cash outflows for construction expenditure to extend the life of the plants, thus a thirty year expected useful life is reasonable. Due to immateriality to the total cash flow, the first 6 months of 2011 were not removed.

Finally, the model does not include any effect of cash from the ultimate sale of any of the plants since these plants are operated in a regulated environment and it would be anticipated that any gain would be returned to the customer.

We applied a 49.8% factor to the 2011 Preliminary Long Range Plan cash flows to estimate the cash flows from the generation function. The June 30, 2011 estimated gross margin was used because it reflects the current rates in effect related to sales other than OSS and also the over/underrecovery of fuel clause in effect in each jurisdiction. The factor represents the estimated generation gross margin for all of the East companies as a percentage of the total gross margin of the combined East companies. This approach is appropriate since the revenues and fuel expenses of the generation function are clearly identifiable on each operating company. (Note that even though the cash flows are clearly identifiable at the operating level, as mentioned previously the cash flows from each unit is dependent upon the other units in the Agreement.) The revenue is comprised of Sales for Resale (affiliated and non-affiliated) and the portion of Retail sales related to generation as described below. The fuel and purchased power expenses relate only to the generation function.

As information, the Retail sales related to generation are unbundled from the total rate charged customers in one of two ways, depending on the way the billing rates are designed. For an unbundled rate company (OPCO, CSP, APCO-VA and I&M-MI), the billing rates are entered into the MACSS system for G, T and D. Unbundled revenue reports provide the billed and unbilled revenues that support the journal entries to unbundle the revenues.

For a bundled rate company (APCO-WV, WPCO, I&M-IN, and KPCO), the various Rate Departments provide factors by rate schedule that are used to unbundle the revenues. These factors are based on rate studies and are input into the MACSS system, which generates unbundled revenue reports which are used to support the journal entries to unbundle the revenues.

A reduction was made to the cash flows for the effect of the CSPAR rules on Off System Sales. An estimated $100 million per year for 2012-2014 was made to reflect this effect. After 2014, the affected plants are forecasted to be retired.

C. Conclusion

As shown below, the estimated generation function cash flows are sufficient to recover the companies' generating assets. No further action is required.

($ millions)						
Total Company Estimated Cash Flows			East Generation Only			
10 year Forecast	20 years based on 2020	30 years (less than average remaining life of assets)	Estimated Generation 49.8% of total Revenues Less Est. CSAPR OSS Impact	Generation PP&E Balance July 2011	Excess Estimated Cash Flow versus Balance	Are Assets Recoverable?
18,843.5	51,336.0	70,179.5	34,798.8	12,528.6	22,270.3	Yes

D. Depreciation

ASC 360-10-35-22 states that if a long-lived asset (asset group) is tested for recoverability, it also may be necessary to review current depreciation estimates and method.

The plants are all being depreciated on their estimated remaining life. All of the unit's lives have been revised to reflect the NSR settlement or the most recent lives approved or filed in recent rate cases.

We are analyzing the current CSAPR rules and timelines, the related political discussions and possible outcomes in conjunction with the Ohio Settlement to determine the action to take related to the Ohio units and their related lives. As of the end of the 3rd Quarter 2011, no final decisions have been made to adjustment the depreciation lives. The current lives are appropriate given the possible outcomes.

Attachment

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