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March 28, 2013

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

Re: PJM Interconnection, L.L.C. and East Kentucky Power Cooperative, Inc.
Docket No. ER13-______-000 (PJM Intra-PJM Tariffs - PJM OATT, OA & RAA)
Docket No. ER13-______-000 (PJM Rate Schedules Tariff - CTOA)
Docket No. ER13-______-000 (PJM Service Agreements Tariff)

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act ("FPA"),[1] PJM Interconnection, L.L.C. ("PJM") and East Kentucky Power Cooperative, Inc. ("EKPC") jointly submit this filing to the Federal Energy Regulatory Commission ("FERC" or "Commission") in connection with EKPC's integration into PJM effective June 1, 2013. In anticipation of integration on June 1, 2013, the Commission previously approved EKPC's request for (i) extension of time to submit its Order No. 1000 compliance filing;[2] (ii) waiver to submit an out-of-time Fixed Resource Requirement Plan ("FRR Plan") for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years;[3] and, (iii) waiver to participate in the PJM Reliability Pricing Model ("RPM") Base Residual Auction for the 2016/2017 Delivery Year.[4]

In this filing, PJM submits modifications to the PJM Open Access Transmission Tariff ("PJM Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("PJM OA"), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("PJM RAA") and the Consolidated Transmission Owners Agreement ("PJM CTOA").[5]

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[1] 16 U.S.C. § 824d (2006).

[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 141 FERC ¶ 61,029 (2012).

[3] *East Kentucky Power Cooperative, Inc.*, 142 FERC ¶ 61,028 (2013).

[4] *Id.*

[5] The modifications to the PJM CTOA are filed by PJM on behalf of the PJM Transmission Owners Agreement

EKPC submits support for modifications to the PJM Tariff related to the establishment and recovery of EKPC's revenue requirements, rate design and provisions of the PJM Tariff governing the recovery of transmission-related costs incurred by EKPC.[6]

In addition, PJM and EKPC describe in this transmittal letter how existing interconnection customers and transmission service customers in the EKPC Zone will transfer to PJM transmission service. The PJM Tariff service agreements, or as appropriate, the existing interconnection service agreements, for these customers will be filed in a separate filing or filings.

I. Background

EKPC is an electric generation and transmission cooperative organized and existing under Chapter 279 of the Kentucky Revised Statutes.[7] EKPC owns approximately $3.1 billion in assets, serving approximately 521,000 homes, business and industries in 87 Kentucky counties through its 16 member distribution cooperatives. EKPC owns and/or purchases nearly 3,100 MW of electric generation capacity and approximately 2,800 miles of electric transmission lines. EKPC has outstanding debt through the Rural Utilities Service and therefore is not a "Public Utility" as defined in the Federal Power Act.[8] However, EKPC currently has on file with the Commission a non-jurisdictional Open Access Transmission Tariff ("EKPC OATT").[9]

PJM is a Commission-approved regional transmission organization ("RTO"). As the public utility transmission provider and the administrator of the PJM Tariff, PJM operates energy and, ancillary services and capacity markets, plans regional transmission expansion improvements to maintain grid reliability and relieve congestion and conducts the day-to-day operations of the transmission system in the PJM Region.[10]

On May 3, 2012, EKPC filed an application with the Kentucky Public Service Commission ("KPSC") seeking authorization to transfer functional control of its 100 kV transmission facilities over to PJM, effective June 1, 2013.[11] On December 20, 2012, the KPSC issued an order ("KPSC Order") conditionally approving EKPC's request to integrate into PJM

Administrative Committee.

[6] The division between PJM and EKPC of filing responsibilities herein are consistent with filing rights allocated to PJM and the PJM Transmission Owners pursuant to section 9 of the PJM Tariff and Article 7 of the PJM CTOA.

[7] Kentucky Revised Statutes, Section 279.010 *et seq*.

[8] 16 U.S.C. § 824(e), (f) (2006).

[9] *East Kentucky Power Cooperative*, Unpublished Letter Order, Docket No. NJ97-14-000 (Dec. 18, 1997); *see also East Kentucky Power Cooperative, Inc.*, 118 FERC ¶ 61,248 (2007); *East Kentucky Power Coop., Inc.*, 121 FERC ¶ 61,012 (2007); *East Kentucky Power Coop., Inc.*, 130 FERC ¶ 61,072 (2010) (affirming "safe harbor" tariff).

[10] The PJM region includes all or parts of the states of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia, as well as the District of Columbia.

[11] EKPC is transferring functional control of its 100 kV and above facilities to PJM. EKPC owns and operates 69 kV facilities, over which it will maintain functional control post-integration.

and to transfer functional control of certain transmission facilities to PJM.[12] On December 27, 2012 EKPC filed with the Commission the KPSC Order as part of its Status Report under Docket ER10-23-000. The KPSC Order approved a stipulation between EKPC, PJM, the Attorney General's Office, Rate Intervention Division ("AG"), and Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") signed on November 2, 2012 ("Stipulation"). Pursuant to the terms of the Stipulation as approved by the KPSC, EKPC shall not unilaterally pursue integration with PJM if FERC does not approve such integration pursuant to the requisite terms of the Stipulation. If FERC deviates from the terms of the Stipulation as approved by the KPSC Order, EKPC must re-start the negotiation process with the parties to the Stipulation, FERC and KPSC to achieve an acceptable resolution. [13]

On November 15, 2012, in anticipation of a June 1, 2013 integration date, EKPC submitted a request to the Commission to authorize EKPC's participation in the Spring, 2013 RPM Base Residual Auction for commitments in the delivery year 2016-2017 with respect to load and resources in the EKPC footprint.[14] Included with the November 15 Filing as "Exhibit 1" for informational purposes was EKPC's technical implementation plan for integration into PJM as memorialized in the *Agreement to Implement Expansion of PJM Region for East Kentucky Power Cooperative* entered into between EKPC and PJM.[15] On November 30, 2012, EKPC filed a petition to submit an out-of-time Fixed Resource Requirement Plan ("FRR Plan") to PJM for the period commencing June 1, 2013 through May 31, 2016 in order to satisfy independent resource adequacy obligations for delivery years 2013-14, 2014-2015 and 2015-2016. By letter order dated January 14, 2013, the Commission granted the requested waiver allowing EKPC to participate in PJM's May 2013 Base Residual Auction for delivery year 2016-2017 prior to EKPC's integration into PJM on June 1, 2013, and accepted EKPC's FRR Plan.[16]

On January 23, 2013, EKPC requested Commission approval of a Transitional Fixed Resource Requirements Plan ("Transitional FRR Plan") as a necessary component of EKPC's integration into and participation in PJM.[17] EKPC explained that the Transitional FRR Plan is an out-of-time Fixed Resource Requirement Plan ("FRR Plan") that permits EKPC to transition into full participation in RPM. EKPC also requested a waiver of, or exemption from, certain provisions of the Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region ("RAA") and of the PJM Open Access Transmission Tariff ("PJM Tariff"), as necessary,

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[12] *In Re: Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC*, Order Conditionally Approving Integration Into PJM, Case No. 2012-00169 (Dec.20, 2012) ("KPSC Order").

[13] KPSC Order at 11.

[14] *East Kentucky Power Cooperative, Inc.*, EKPC Filing Letter, Docket No. ER13-414-000 (Nov. 15, 2012) ("November 15 Filing").

[15] *See Agreement to Implement Expansion of PJM Region for East Kentucky Power Cooperative* entered into between East Kentucky Power Cooperative and PJM Interconnection, L.L.C. (Jan. 9, 2012).

[16] *East Kentucky Power Cooperative*, 142 FERC ¶ 61,028 (2013) ("January 14 Order"). On January 16, 2013, EKPC submitted an informational filing to the Commission advising that EKPC's commencement of service under the FRR Plan was deferred from February 1, 2013 to March 1, 2013.

[17] *East Kentucky Power Cooperative, Inc.*, EKPC Filing Letter, Docket No. ER13-793-000 (Jan. 23, 2013).

to permit EKPC's implementation of the Transitional FRR Plan. This request remains pending before the Commission.

II. Description of Filing

A. PJM's Revisions to the PJM Tariff, PJM OA, PJM RAA and PJM CTOA

PJM's revisions to the PJM Tariff, PJM OA, PJM RAA and PJM CTOA are needed to implement the integration of the EKPC Zone into the PJM Region on June 1, 2013. These changes are ministerial in that they add, where needed, the EKPC Zone and/or EKPC as a Transmission Owner to the PJM Tariff, PJM OA, PJM RAA and PJM CTOA.

1. PJM Tariff and PJM OA Revisions[18]

a. PJM Tariff Attachment J, PJM Transmission Zone

The PJM Tariff, Attachment J lists the Transmission Zones in the PJM Region. Attachment J also includes a map of the PJM region depicting the PJM Transmission Zones. PJM proposes to amend Attachment J to include the EKPC Zone in the PJM Region.

Schedule 4 of the PJM OA, which is the standard form of agreement to become a member of PJM, requires a copy of Attachment J from the PJM Tariff marked to show changes to the PJM Region boundaries if membership requires expansion of the PJM Region to integrate the new members. In this case, the integration of EKPC required a copy of Attachment J from the PJM Tariff marked to show changes to the PJM Region boundaries. The proposed revisions to Attachment J are consistent with the maps that were attached by EKPC when it signed Schedule 4 of the PJM OA.

b. PJM Tariff Attachment C-3, Conversion of Service in the EKPC Zone

PJM proposes to add a new Attachment C-3 to the PJM Tariff. Attachment C-3 provides information on the conversion of transmission service and interconnection service in the EKPC Zone from the existing service under the EKPC OATT[19] to service under the PJM Tariff with respect to EKPC's integration into PJM. Attachment C-3 sets forth the principles that shall govern such conversion.

More specifically, Attachment C-3 sets forth the principles under which existing transmission service reservations in EKPC will be converted to the most closely analogous service under the PJM Tariff. Attachment C-3 will address the conversion process for transmission service with an export from the EKPC Zone and an import to the remainder of the PJM Region (or vice-versa). Not all transmission service provided under the EKPC OATT exactly matches a service under the PJM Tariff. Variances in transmission service requests will

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[18] PJM's revisions to the PJM Tariff, PJM OA and PJM RAA were endorsed by the PJM Members Committee on March 28, 2013.

[19] *See supra* note 9.

be converted into defined product types under the PJM Tariff as more fully explained in Attachment C-3. In addition, Pre-Order No. 888[20] service will be maintained or "Grandfathered."[21]

Regarding conversion of the existing EKPC transmission service agreements, the only existing EKPC customer that will require a new Network Integration Transmission Service Agreement ("NITSA") post-integration is LG&E/KU, to whom PJM has tendered a new NITSA. A new service agreement will be filed with the Commission and assigned a PJM service agreement number. Duke Energy Ohio/Duke Energy Kentucky ("DEOK") is also a network service customer under the EKPC OATT. EKPC will issue a Notice of Cancellation of the DEOK service agreement by April 1, 2013. However, a replacement agreement is not necessary because DEOK is already a member of PJM and already has in place a service agreement with PJM.

Attachment C-3 also addresses interconnection service migration – both for pending interconnection requests as well as for existing interconnection customers with interconnection agreements. Interconnection requests that are pending in the EKPC interconnection queue as of June 1, 2013 will be migrated into PJM's interconnection queue with queue priority that is based on the date the interconnection customer entered EKPC's queue. PJM will pick up the study process where it was left off in the EKPC study process.

With respect to existing interconnection customers, PJM is working with each customer to ensure interconnection service is maintained and that interconnection customers who were under interconnection agreements prior to June 1, 2013 will retain deliverability of their generating units at no additional interconnection cost to interconnection customers to the extent they are not modifying their facilities. The new interconnection service agreements or revised interconnection agreements will be filed with the Commission.

c. PJM Tariff Schedule 10 – NERC and Schedule 10 – RFC

PJM proposes revisions to the PJM Tariff to exclude the EKPC Zone as part of the Schedule 10 – NERC and Schedule 10 – RFC rate schedules that permit the collection of charges from end users in PJM that are necessary to support, respectively, the operations of the North American Electric Reliability Corporation ("NERC") and the Reliability First Corporation ("RFC") until January 1, 2014.

PJM adopted Schedule 10 – NERC and Schedule 10 – RFC rate schedules in December 2006, in Docket No. ER07-294-000 for the sole purpose of facilitating the billing and collection of the fees charged by NERC and RFC. The collection of fees in this manner spares NERC and RFC the burden of separately billing dozens of end users for these charges and separately

[20] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, 31,665 ("Order No. 888"), *clarified,* 76 FERC ¶ 61,009, and 76 FERC ¶ 61,347 (1996), *order on reh'g,* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *clarified,* 79 FERC ¶ 61,182, *order on reh'g,* Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd, Transmission Access Policy Study Group v. FERC,* 225 F.3d 667 (D.C. Cir. 2000) ("*TAPS*") (*per curiam*), *aff'd sub nom. New York v. FERC*, 535 U.S. 1, 122 S.Ct. 1012, 152 L.Ed.2d 47 (2002).

[21] Grandfathered service refers to transmission agreements that pre-date FERC Order No. 888. *Id.*

keeping track of the proportional responsibility for energy deliveries that serves as the basis for cost allocation. Because PJM already bills these end users and keeps current the relevant usage information for its own purposes, PJM's voluntary performance of this service achieves an administrative efficiency that is in the public interest.

The current Schedule 10 – NERC language provides that PJM will charge each customer using Network Integration and Point-to-Point Transmission Service each month a charge equal to the NERC Rate times the total quantity in MWHs of energy delivered to the load (including losses) that each customer serves in the PJM Region, excluding the Dominion Zone. PJM proposes to modify this language to exclude the EKPC Zone from this provision because NERC's 2013 approved annual budget contemplated that it would include the EKPC Zone in its direct billing and collection. Further, a modification to exclude the EKPC Zone from the total hourly load calculation in Schedule 10 – NERC is also proposed.

Similarly, current Schedule 10 – RFC language provides that PJM will charge each customer using Network Integration and Point-to-Point Transmission Service each month a charge equal to the RFC Rate times the total quantity in MWHs of energy delivered to load (including losses) that each customer serves in the PJM region, excluding the EKPC Zone. PJM proposes to modify this language to exclude the EKPC Zone from this provision for the same reason as described above for Schedule 10-NERC. A modification to exclude the EKPC Zone from the total hourly load calculation in Schedule 10 – RFC is also proposed.

These PJM Tariff revisions do not increase existing rates or establish any new rate. They merely reflect minor modifications in the billing and collection of Commission-approved rates to reflect the fact that EKPC is paying these rates directly to NERC and RFC for 2013.

d. PJM Tariff Attachment DD, Section 5.10, Cost of New Entry

PJM proposes to revise PJM Tariff, Attachment DD Section 5.10 by adding the EKPC Zone to the chart of "Geographic Location within the PJM Region Encompassing These Zones." Attachment DD Section 5.10 contains the requirements under which PJM must clear each Reliability Pricing Model's Base Residual Auction and Incremental Auction for a Delivery Year. These requirements include the use of a Cost of New Entry ("CONE") for the Transmission Zones that comprise each Locational Deliverability Area ("LDA") in the PJM Region, as set forth in the table in Section 5.10. The EKPC Zone is included in "CONE Area 3 on the chart which currently includes AEP, Dayton, ComEd, APS, DQL, ATSI and DEOK.

e. PJM Tariff Attachment K – Appendix and PJM OA Schedule 1, Section 3.2.2 (q)

PJM proposes to revise Section 3.2.2 (q) in PJM Tariff Attachment K- Appendix and in PJM OA Schedule 1 by adding the EKPC Zone to the transmission zones for the Western Region of the PJM. Section 3.2.2 contains the Operating Reserve rules applicable to Market Sellers' generator units that participate in the PJM markets. Sub-paragraph (q) sets forth how PJM determines the regional balancing Operating Reserve rates for the Western and Eastern Regions. The EKPC Zone is a Western Region transmission zone for purposes of balancing Operating

Reserve rates because the EKPC Zone is more electrically contiguous with the zones in the Western Region of PJM than with any other zones or collection of zones in the PJM Region.

f. PJM Tariff Attachment K – Appendix and PJM OA Schedule 1, Section 7.4.2 (b)

Section 7.4.2 (b) in PJM Tariff Attachment K- Appendix and in PJM OA Schedule 1 provides for the Auction Revenue Rights ("ARRs") allocation process to be performed by PJM. Under Section 7.4.2 (b), in stage 1A of the ARR allocation process, each Network Service User may request ARRs for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period, with the sources for the ARRs being a subset of the historical generation resources that were designated to be delivered to load during the historical reference year for the zone. Also under Section 7.4.2(b) in stage 1A of the ARR allocation process, each Qualifying Transmission Customer (as defined in subsection (f) of Section 7.4.2) may request ARRs based on the MWs of firm service provided between the receipt and delivery points where the Transmission Customer had reserved firm Point-to-Point Transmission Service during the historical reference year.

While the historical reference year for all Zones in PJM is 1998, Section 7.4.2 (b) sets forth the historic reference years for all zones which integrated into PJM after 1998. Under Section 7.4.2 (b), PJM "shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Markets." Because the EKPC Zone will integrate into PJM during 2013, PJM proposes to revise Section 7.4.2 (b) in PJM Tariff Attachment K- Appendix and in PJM OA Schedule 1 by adding "the EKPC Zone historic reference year; 2013."

g. PJM Tariff, Attachment L, List of Transmission Owners

Transmission owners in PJM are listed in Attachment L to the PJM Tariff. The PJM Tariff defines "Transmission Owner" as: "[e]ach entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the Tariff."[22] EKPC meets this definition. Thus, PJM submits for filing a revised Attachment L to the PJM Tariff adding EKPC to the list of PJM transmission owners.

h. PJM OA Schedule 12, PJM Member List

PJM revises the PJM OA Schedule 12 Member List to correct the reference to EKPC to include its correct legal name.

2. PJM RAA Revisions

a. PJM RAA Schedule 10.1, Locational Deliverability Areas and Requirements

[22] PJM Tariff, Section 1.45F.

PJM RAA Schedule 10.1 lists the Zones, combination of Zones and portions of such Zones in the PJM Region which make up the LDAs for purposes of determining locational capacity obligations under the RAA. Thus, PJM proposes to revise Schedule 10.1 by adding the EKPC Zone. Also, PJM adds EKPC to the larger LDA that is currently defined as ComEd, AEP, Dayton, APS and Duquesne. As stated above, the EKPC Zone is more electrically contiguous with the zones in the Western Region of PJM than with any other zones or collection of zones in the PJM Region.

b. PJM RAA Schedule 15, Zones Within the PJM Region

Schedule 15 to the PJM RAA lists the Transmission Zones in the PJM Region in the same manner as PJM Tariff Attachment J discussed above. Like PJM Tariff Attachment J, PJM RAA Schedule 15 also includes a map of the PJM Region depicting the PJM Transmission Zones. Thus, PJM proposes to amend Schedule 15 to include the EKPC Zone in the PJM Region.

c. PJM RAA Schedule 17, Parties to the RAA

Because EKPC is also a Load Serving Entity, it is required to sign the PJM RAA.[23] EKPC, therefore, signed the PJM RAA on February 28, 2013, in accordance with Section 11.6 (b) of the PJM OA and PJM now revises the PJM RAA Schedule 17 to include EKPC.

3. PJM CTOA Revisions, Addition of EKPC to List of PJM Transmission Owners

Attachment A to the PJM CTOA lists the transmission owners in the PJM Region.[24] In preparation for the EKPC Zone integration on June 1, 2013, EKPC signed the PJM CTOA on March 26, 2013. The transmission owners under the PJM CTOA are listed in Attachment A of the CTOA. The PJM Tariff defines "Transmission Owner" as: "[e]ach entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the Tariff." The transmission owners are listed in Attachment L to the PJM Tariff.[25] The PJM CTOA contains a similar definition which states that Transmission Owner "shall mean those entities that own or lease (with rights equivalent to ownership) Transmission Facilities . . . ."[26]

EKPC will be a PJM transmission owner on June 1, 2013, because, on that date, the EKPC's transmission facilities will: (i) be within the PJM Region; (ii) meet the definition of transmission facilities in Section 1.27 of the PJM CTOA; and (iii) have been demonstrated to the satisfaction of PJM to be integrated with the Transmission System of the PJM Region and integrated into the planning and operation of such.[27]

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[23] *See* PJM OA, Section 11.6 (b); and PJM RAA, Article 4.

[24] *See* PJM CTOA, Section 1.28.

[25] PJM Tariff, Section 1.45F.

[26] PJM CTOA, Section 1.28.

[27] PJM CTOA, Section 1.27.

Therefore, PJM hereby submits for filing, as part of the PJM CTOA, a signature page to the PJM CTOA executed by EKPC. PJM also submits for filing a revised Attachment A to the PJM CTOA adding EKPC to the list of PJM transmission owners.

B. Continuity of Service and Replacement Arrangements for Continued Transmission Service to OATT Customers, and EKPC Revisions to the PJM Tariff Related to the Establishment and Recovery of EKPC's Revenue Requirements and Rate Design.

The replacement arrangements proposed in this filing satisfy the Commission's requirements for maintaining the continuity of service to transmission tariff customers. EKPC provides transmission service over the EKPC system pursuant to the "safe harbor" EKPC OATT filed with the Commission. Post integration, the EKPC OATT will be cancelled and transmission service over the EKPC system will be provided under the PJM Tariff – a Commission-approved open access transmission tariff. The PJM Tariff complies with the Commission's *pro forma* OATT and any provisions that differ from the *pro forma* OATT have been approved by the Commission. As shown below, the replacement arrangements maintain the status quo with respect to transmission rates and service for transmission customers in the EKPC Zone, with limited exceptions that are just, reasonable, and not unduly discriminatory.

1. Continuity of Service

a. Conversion of Existing Network Customers

EKPC has two existing network customers: Duke Energy Ohio/Kentucky ("DEOK") and LG&E/KU. By April 1, 2013, EKPC will submit a Notice of Cancellation of the DEOK agreement. DEOK is already a PJM customer and already has in place a network service agreement with PJM. Therefore, a replacement agreement is not necessary.

EKPC will also submit by April 1, 2013 a Notice of Cancellation of the LG&E/KU network service agreement, for which a replacement NITSA ("LG&E/KU Replacement NITSA") will be necessary. However, as described below (section II.B.1.d.i), the LG&E/KU Replacement NITSA contains provisions that vary from the standard PJM NITSA. These terms and conditions are necessary to comply with the December 20, 2012 Order of the KPSC.

b. Conversion of Existing Point-to-Point Customers

As of the date of this filing, there are no existing point-to-point customers with current reservations under the EKPC OATT. By April 1, 2013, EKPC will post a notice on its OASIS site informing the public that the EKPC OATT will be cancelled effective June 1, 2013 and that any new point-to-point reservations must be made under the PJM Tariff.

c. Pending and Existing Interconnection Customers

As noted *supra*, Section II.A.1.b, interconnection requests that are pending in the EKPC interconnection queue as of June 1, 2013 will be migrated into PJM's interconnection queue with queue priority that is based on the date the interconnection customer entered EKPC's queue. PJM will pick up the study process where it was left off in the EKPC study process.

PJM is also working with each existing EKPC interconnection customer to ensure interconnection service is maintained and that interconnection customers will retain deliverability of their generating units at no additional interconnection cost to interconnection customers, to the extent those interconnection customers are not modifying their facilities. All new interconnection service agreements or revised interconnection agreements will be filed with the Commission.

d. Maintenance of Existing Arrangements for Purposes of Integration

EKPC has in place the following four long-standing arrangements which EKPC and PJM have agreed to continue after EKPC integrates into PJM:

1. The first involves satisfying conditions of the KPSC Order regarding the treatment of LG&E/KU load served from the EKPC transmission system, and *vice versa*.
2. The second involves maintaining the historical practice of performing limited load switching between the highly integrated EKPC and LG&E/KU systems, and between the EKPC and Tennessee Valley Authority ("TVA") systems.
3. The third involves maintaining an arrangement between EKPC and American Electric Power ("AEP"), pursuant to a service schedule and practice dating back to 1963.
4. The fourth and final is a long term firm transmission arrangement that EKPC has had in place since 1984 to deliver its entitlements from the Southeastern Power Administration. Each of these arrangements is more fully described below.

i. Treatment of LG&E/KU load on EKPC System

EKPC and PJM have worked diligently to pursue necessary regulatory approvals for EKPC's integration into PJM. On December 20, 2012, the KPSC issued its order conditionally approving EKPC's application to transfer functional control of its transmission facilities operated at 100 kV and above to PJM.[28] Among the issues raised in the KPSC proceeding was the treatment of LG&E/KU load on the EKPC system. EKPC's and LG&E/KU's systems are heavily interconnected, given the geographic proximity of the two systems and the fact that the companies share 67 interconnection points between their transmission systems. The companies also use each other's facilities to serve their respective customers through numerous load interconnection points. LG&E/KU serves approximately 100 MW (peak) of their native-load using EKPC's transmission system. Conversely, EKPC serves approximately 450 MW of its native-load using LG&E/KU's transmission system. EKPC and LG&E/KU are signatories to a Network Integration Transmission Service Agreement which provides for LG&E/KU to pay EKPC rates to use EKPC's transmission system. The EKPC rates are set forth in EKPC's Safe Harbor OATT, which is on file with FERC.

The Stipulation is, in general, intended to hold LGE/KU harmless from additional charges that LG&E/KU might incur as a result of EKPC joining PJM.[29] The KPSC adopted and

[28] KPSC Order at 20-21.

incorporated the Stipulation into its Order.[30] Pursuant to the Stipulation, LG&E/KU load that is connected to EKPC's transmission system will continue to be pseudo-tied into the LG&E/KU Balancing Area, and therefore shall be electrically outside of the PJM region and PJM markets.[31] To accomplish this, the Stipulation provides that LG&E/KU will make payments for transmission service under Schedules 7, 8 and/or Attachment 24 of the PJM Tariff at the EKPC zonal transmission rate that is calculated based on EKPC's transmission revenue requirements in effect at the time.[32]

In recognition of the LG&E/KU load being treated as outside of the PJM Balancing Area, the Stipulation provides PJM shall not charge LG&E/KU any other rates or charges that are assessed on load that is within the PJM Markets pursuant to the PJM Tariff, including, but not limited to Regional Transmission Expansion Plan ("RTEP"), locational marginal prices ("LMP"), congestion, and other administrative costs. This provision applies only to charges for transmission service for the LG&E/KU load and does not address costs that may develop in furtherance of possible future, unknown Commission policies or requirements.[33] As a result of these unique requirements for the provision of NITS to the LGE/KU Load by PJM, PJM entered into a NITSA with LGE/KU with non-conforming provisions. The LGE/KU Load NITSA is attached to this transmittal letter.[34] The non-conforming terms of the NITSA are necessary to incorporate into the NITSA by reference the Stipulation. PJM submits these non-conforming revisions to the *pro forma* NITSA are required to address the unique circumstances of the NITS for the LGE/KU Load.[35] Moreover, PJM submits the non-conforming LGE/KU Load NITSA is just and reasonable.[36] The Stipulation also provides that LG&E/KU will contract with EKPC to provide Ancillary Services Schedule 1 (Scheduling, System Control and Dispatch Service) and Ancillary Services Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service). Charges for these services must be based on the terms and conditions of the EKPC OATT and will be set forth in the contract between LG&E/KU. EKPC may modify the rates for these ancillary services, but the rates will continue to be based only on EKPC costs and not PJM costs.[37] The parties' agreement to these conditions is subject to Commission acceptance.

LG&E/KU agreed to reciprocal provisions for EKPC that recognized EKPC's load that is connected to the LG&E/KU system as being pseudo-tied into the PJM Balancing Area, so it will

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[29] *Id.* at 10.

[30] *Id.* at 21.

[31] *Id.* at 10.

[32] *Id.*

[33] *See* Stipulation at 2.1.3.

[34] This is one of two service agreements included in the documents submitted under "Attachment B" hereto.

[35] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 11 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[36] *See NewCorp Resources Electric Cooperative, Inc.*, 109 FERC ¶ 61,103 (2004).

[37] KPSC Order at 10.

be treated as EKPC zonal load under the PJM Tariff. LG&E/KU further agreed that EKPC will not be subject to any regional transmission expansion costs or any comparable costs incurred by LG&E/KU arising from the LG&E/KU involvement in the Southeastern Regional Transmission Planning group.[38]

ii. Maintaining Practice of Load Switching

EKPC and LG&E/KU have interconnected and integrated systems with load located on each others' transmission systems. Similarly, EKPC and TVA have interconnected systems. Each of these entities has a long-standing reliability practice of performing load switching during maintenance and load restoration periods. This practice is recognized by the KPSC and with respect to LG&E/KU is a condition of the KPSC Order approving EKPC's integration into PJM.[39] Load switching occurs when Utility A transfers its load connected to Utility A's transmission system to Utility B for the duration of scheduled maintenance or while this load is being restored. Utility A provides an estimated energy schedule for this load to Utility B. Once restored, Utilities A and B agree to a schedule in order to return-in-kind any discrepancy of the estimated schedule. Energy is returned-in-kind with no monetary exchange. This practice provides a reliable and efficient of way restoring load or performing maintenance on facilities while continuing to provide service to the affected customers.

EKPC, TVA and LG&E/KU seek the ability to continue to perform limited load switching without incurring PJM Tariff charges. Commission approval is needed to permit PJM to allow the provision of for these limited load switches, without applying PJM Tariff charges for such service. As a result of this arrangement, congestion and losses charges will not be assessed against TVA, LG&E/KU or EKPC. However, increases, if any, in LMP resulting from costs of re-dispatch of generation out of economic order will be paid by EKPC load.

iii. Interconnection Agreement between AEP and EKPC

EKPC and AEP are seeking to maintain for purposes of integration the historical terms and conditions of an existing Interconnection Agreement ("IA"). The agreement incorporates a 1963 service schedule which provides for reciprocal transmission service ("Exchange Service") for EKPC native load connected to the AEP transmission system and for AEP native load connected to the EKPC transmission system. The EKPC load on the AEP system has recently averaged around 7.5 MW peak per month, while the AEP load on the EKPC system has recently averaged just under 16 MW peak per month.

Pursuant to the IA, each party delivers to the other party capacity and energy to supply its load on the other party's system, plus associated losses. Each party pays the other party for transmission service to the specified delivery point at a specified rate per kWh of energy delivered to the subject delivery points. AEP and PJM have agreed to allow the IA to stay in effect following EKPC's integration into PJM. To maintain existing practice, the load supplied under the Exchange Service provisions of the IA will be netted out from the EKPC load reported to PJM for transmission billing purposes.

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[38] Stipulation, Section 2.1.6.

[39] Stipulation, Section 2.4.

This agreement is already listed as a PJM service schedule (No. 1530) by virtue of AEP's filing of that agreement. This instant request for Commission approval is thus only precautionary.

iv. Southeastern Power Administration Firm Transmission Arrangements

EKPC has existing pre-Order No. 888 Grandfathered firm transmission rights to import and deliver energy and capacity from the Southeastern Power Administration ("SEPA") to EKPC, which EKPC requests to continue after EKPC's integration into PJM. For this pre-Order No. 888 Grandfathered service, EKPC will receive from PJM an allocation of credits to offset congestion charges and losses that would otherwise apply to deliveries by SEPA into the EKPC transmission system.

EKPC holds an entitlement to 170 MW of capacity and associated energy from SEPA's Cumberland Projects, including the 70 MW Laurel Project and 100 MW from other Cumberland Projects. When Laurel is unavailable, EKPC is able to call on other Cumberland Projects. SEPA delivers EKPC's entitlement from the Cumberland projects to EKPC's point of interconnection using the TVA system. In addition, SEPA delivers the entitlement from the Laurel Project to the Laurel Project's interconnection with EKPC's transmission system at the bus in the Laurel Project's switchyard. EKPC has relied on firm use of its transmission system to deliver the SEPA power and energy from its border receipt points to its load centers.

EKPC has used its firm transmission service since 1984, first to enable delivery of its SEPA entitlements under contract no. 89-00-1501-635, dated June 30, 1984, and now to accomplish delivery of the same entitlements under the successor contract no. 89-00-1501-1136, dated June 30, 1998. The underlying use of the EKPC transmission system to deliver the SEPA power and energy to EKPC's load centers has continued since 1984. In recognition of this pre-OATT transmission service, EKPC has requested no transmission rights, and as such, PJM will not charge any congestion or losses for these deliveries between the specified receipt and delivery points, assuming FERC approval of EKPC's requested grandfathered treatment.

2. Transmission and Ancillary Services Rates

While EKPC is not a public utility within the meaning of section 201 of the FPA,[40] and is not subject to the Commission's jurisdiction under sections 205 and 206 of the FPA, the Commission has jurisdiction over the rates for transmission service provided by PJM, an RTO that is a public utility. Court precedent provides that when a non-jurisdictional transmission owner voluntarily joins an RTO, the Commission "can ensure by examining [the non-jurisdictional utility's revenue requirement] that the [RTO's] rates will ultimately be just and reasonable."[41] In performing its examination of the non-jurisdictional entity's rates, the

[40] 16 U.S.C. § 824(e) (2006).

[41] *Pacific Gas & Elec. Co. v. FERC*, 306 F.3d 1112, 1114, 1117 (D.C. Cir. 2002) ("*PG&E*") (finding that because governmental entities are exempt from the FPA, FERC cannot regulate them even when they join regulated ISOs. However, FERC may analyze and consider the rates of non-jurisdictional utilities to the extent that those rates affect

Commission applies the "just and reasonable" standard under the FPA.[42] EKPC is the first non-jurisdictional transmission owner to seek recovery of rates within the PJM region. However, the Commission has accepted transmission revenue requirements and transmission formula rates submitted by or on behalf of non-jurisdictional entities in other RTO regions.[43]

Accordingly, EKPC submits its formula rate and supporting information for the purpose of permitting the Commission to review EKPC's rates to be included in the PJM Tariff. EKPC has made every effort to present its information in a manner consistent with the Commission's ratemaking criteria. Because it is a rural electric cooperative, EKPC does not file a FERC Form No. 1, which is typically the source of much of the data presented by jurisdictional utilities in rate proceedings before the Commission. However, EKPC does prepare a report on its finances and expenses each year, which is filed with the KPSC.[44] EKPC's Formula Rate Template and its Implementing Protocols refer to this report as the "EKPC Form FF1." Tying the EKPC formula rate inputs to the EKPC Form FF1 ensures that the data underlying EKPC's annual transmission revenue requirement is current, transparent and objectively verifiable. Any data not directly pulled from the EKPC Form FF1 has been provided in supporting work papers. The formula rate, supporting work papers and accompanying protocols are described in more detail below, and in the accompanying testimony of Ms. Ann Wood[45] and Mr. Daniel Cooper,[46] on behalf of EKPC.

EKPC believes that the information contained in this filing provides sufficient information for the Commission to find that inclusion of EKPC's rate formula in the PJM Tariff is just and reasonable. In the event that the Commission determines that this filing requires further proceedings to determine whether EKPC's rates are just and reasonable, EKPC requests that the filed rates be allowed to go into effect on June 1, 2013 in order to facilitate EKPC's integration with PJM. EKPC is requesting acceptance of its formula rate without suspension or hearing. However, in the event the Commission determines further proceedings are necessary in order to complete its evaluation of EKPC's rate formula, EKPC offers to treat its rates as being in effect, subject to refund with interest at FERC interest rates.

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jurisdictional transactions); *see also Transmission Agency of Northern Calif. et al. v. FERC*, 495 F.3d 663, 671-72 (D.C. Cir. 2007) ("*TANC*").

[42] *City of Vernon, California*, 93 FERC ¶ 61,103, 61,285 (2000), *reh'g denied*, 94 FERC 61,148, *aff'in part sub nom. PG&E*, 306 F.3d 1112, *remanded to City of Vernon, California*, Opinion No. 479, 111 FERC ¶ 61,092, *order on reh'g*, Opinion No. 479-A, 112 FERC ¶ 61,207 (2005), *reh'g denied*, Opinion No. 479-B, 115 FERC ¶ 61,297 (2006), *aff'd sub nom. TANC*, 495 F.3d 663.

[43] *Id., See also, e.g., Sw. Power Pool, Inc.*, 138 FERC ¶ 61,231 (2012), *order on reh'g*. 142 FERC ¶ 61,135 (2013); *Valley Electric Assn.*, 141 FERC ¶ 61,238 (2012); *Sw. Power Pool, Inc.*, Unpublished Letter Order, Docket No. ER11-2309-000 (Jan. 31, 2011); *Sw. Power Pool, Inc.*, Unpublished Letter Order, Docket No. ER09-257-000 (Jan. 27, 2009); *City of Pasadena, California*, 137 FERC ¶ 61,045 (2011).

[44] See Attachment C, Exh. EKP-1 at 3-4. The most recent EKPC Form FF1 (for calendar year ending December 31, 2012) will be filed with the KPSC by April 1, 2013. The KPSC publishes this information on its website. However, it may be several days before the KPSC publishes the information. The relevant pages from EKPC's Form FF1 are not available in a format that meets the Commission's electronic filing requirements as of the date of this filing. However, EKPC will post the EKPC Form FF1 to an FTP site that it can be accessed by Commission Staff. Additionally, anyone wishing to obtain the EKPC Form FF1 may contact EKPC's counsel.

[45] See Attachment C, Exh. EKP-1.

[46] See Attachment C, Exh. EKP-2.

a. Changes in Rates from Existing EKPC OATT

The proposed PJM Tariff amendments will give EKPC's existing transmission customers continued access to transmission service under rates, terms and conditions that are comparable to those available under the present EKPC OATT. However, there are differences in structures between PJM and EKPC's present operation as a stand-alone utility. As a result, the transmission and ancillary service rates that customers in the EKPC Zone will pay post-integration will be slightly different following EKPC's integration into PJM.

One such difference includes the billing determinants used for NITS. EKPC's present OATT calculates billing determinants for NITS charges on a 12-coincident peak ("12 CP") basis, applied against 15 minute integrated peak meter readings. Following EKPC's integration into PJM, rates for NITS will be based upon an annual coincident peak ("1 CP") basis, applied against 60 minute integrated meter data. This change is required to conform to the PJM Tariff.[47] Charges for Firm and Non-firm Point-to-Point service will continue to be applied against the amount reserved, consistent with the terms and provisions for Schedule 7 and Schedule 8 under the PJM Tariff. Another difference is that charges for ancillary services in the EKPC Zone will also be developed and applied in accordance with the PJM Tariff.

i. Legacy and Transitional Charges

EKPC has no legacy costs or transition costs because EKPC is not currently a member of any RTO and has no third party wholesale customers connected to its transmission system that will be taking service from PJM. EKPC will recover only those direct internal costs and legal expenses incurred in negotiating and implementing EKPC's integration into PJM as a part of its transmission revenue requirements. As discussed in Ms. Ann Wood's testimony, EKPC proposes to amortize these costs over a three (3) year period.[48]

ii. PJM RTEP Project Costs

As a new entrant to PJM, EKPC has no facilities that are a part of any PJM Reliability Transmission Expansion Plan ("RTEP") project. However, EKPC's proposed formula transmission rate template contains provisions for calculating EKPC's costs for any RTEP facilities that PJM may assign to EKPC.

Appendix B to EKPC's proposed formula rate template contains the formula for deriving the annual revenue requirement for any RTEP project that PJM assigns to EKPC. The revenue requirements calculated under Appendix B will be provided to PJM for developing zonal rates under PJM Tariff Schedule 12. That same revenue requirement derived in Appendix B and provided to PJM for inclusion in PJM Tariff Schedule 12 rates will be used to offset the zonal revenue requirements in EKPC's formula rate. These revenue credits are included on page 1, line 5a, of the formula rate as the Transmission Enhancement Credit.[49]

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[47] See Attachment C, Exh. EKP-2 at 5.

[48] Attachment C, Exh. EKP-1 at 6.

[49] *See* Attachments A and B, OATT Attachment H-24A; *see also* Attachment D, Exh. EKP-3, Attachment H-24A (populated).

iii. Forward-looking Formula Rate Template

a. Transmission Rates

EKPC proposes to adopt a forward-looking formula rate template to determine transmission rates. EKPC's proposed formula is similar to other formula rate templates accepted by the Commission in the PJM Tariff.[50] EKPC based its rates for transmission service in the EKPC Zone upon EKPC's zonal revenue requirement. This is consistent with the manner in which other PJM Transmission Owners calculate such rates.[51]

EKPC is proposing to incorporate revenue requirements and rates for four transmission and ancillary services under the PJM Tariff:

1. Network Integration and Point-to-Point Transmission Service (PJM Tariff, Attachment H-24A);

As noted above, EKPC will use a "forward looking" formula rate to determine rates for Schedules 7 (non-firm Point-to-Point service), 8 (firm Point-to-Point service) and Attachment 24 (NITS) for the EKPC Zone, with an annual true-up adjustment. EKPC will calculate the prior year reconciliation and the NITS rate for the coming rate-year under by May 15th of each year, and transmit that rate to PJM for inclusion in the PJM Tariff. The resulting rate will continue in effect from each June 1 until the following May 31.

2. Transmission Owner Scheduling, System Control, and Dispatch Service ("Scheduling Service") (PJM Tariff, Schedule 1A);

To calculate the rate for Scheduling Service under the PJM Tariff, EKPC will use the expenses it has booked to Uniform System of Accounts Account No. 561. The calculation of EKPC's Schedule 1A charges appear as Appendix A to Attachment H-24A to the PJM OATT. Those costs included in EKPC's Schedule 1A rate are removed from EKPC's revenue requirements to prevent double-counting of those costs. As with the formula rate for Schedules 7, 8 and Attachment 24 NITS, the EKPC Schedule 1A rate will be recalculated annually by each May 15th based on prior year's actual costs, including an adjustment for any under-collection or over-collection in the preceding calendar year, and will be in effect from June 1 to the following May 31.

EKPC is also modifying Part B of Schedule 1A of the PJM Tariff. Part B allocates the revenues from Scheduling Service provided to Non-Zone Load among the PJM Transmission Owners. In order for EKPC to receive a share of this credit, it will be necessary for EKPC and the other PJM Transmission Owners to review this distribution through a stakeholder process, to determine what share of the credit EKPC will receive. EKPC will pursue this matter subsequent to this filing, and make the necessary changes to Part B. For now, Part B is being modified to add

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[50] *PJM Interconnection, L.L.C., et al.*, 139 FERC ¶ 61,068 (2012) (accepting filed formula rate changes to the PJM Tariff subject to a compliance filing), Unpublished Letter Order, Docket Nos. ER12-91-003, ER12-92-003 (June 29, 2012) (accepting compliance filing).

[51] *Id.*

EKPC to the list of Transmission Owners, and to indicate that EKPC's share of the credit is currently 0.00%.

b. Rate Protocols Accompanying the Proposed Formula Rate

EKPC has included Formula Rate Implementation Protocols as Attachment H-24B to its formula rate. These protocols provide for EKPC to calculate annually a reconciliation amount equal to any difference between EKPC's actual recovery and EKPC's actual ATRR for the preceding year. The reconciliation amount will be used in developing the EKPC zonal transmission rates for the coming Rate Year, consistent with EKPC's Attachment H-24A and H-24B. The EKPC Formula Rate protocols provide stakeholders the opportunity to review and monitor the implementation of the formula rate and are described in more detail in Mr. Cooper's testimony.[52]

c. Depreciation Rates under the Proposed Formula Rate

The protocols included in Attachment H-24B state that depreciation shall be stated values until changed pursuant to a filing made effective by the Commission. To comply with this requirement, EKPC included those items as separately identifiable line items, including identification of the individual components of the transmission depreciation rates that will be used in the formula rate. The effective EKPC depreciation rates for transmission are contained in Appendix D to EKPC's Attachment H-24A. The depreciation rates included in the formula rate, as discussed in Ms. Wood's testimony, are the same as were approved for EKPC by the KPSC.[53]

III. <u>Other Related Filings</u>

EKPC and/or PJM will submit to FERC additional future filings in relation to EKPC's integration into PJM. EKPC anticipates that these filings will be made no later than April 1, 2013, which will be well in advance of its June 1, 2013 integration into PJM. These additional filings will include the following:

A. The Notice of Cancellation of EKPC OATT.[54] The EKPC OATT will no longer be necessary once EKPC integrates into PJM. The Notice of Cancellation will include cancellation of the tariff itself and all service agreements there under.

B. Cancellation of the existing NITSA between EKPC and PJM. EKPC currently has in place with PJM a NITSA[55] to provide EKPC with the transmission service needed to serve EKPC load that is connected to transmission lines owned by PJM member Duke Energy. PJM will request Commission approval to terminate this NITSA as of

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[52] Attachment C, Exh. EKP-2 at 18-19.

[53] Attachment C, Exh. EKP-1 at 5.

[54] PJM has established a page on its website dedicated to the integration of EKPC into PJM. *See* http://www.pjm.com/markets-and-operations/market-integration/ekpc.aspx.

[55] PJM filed the NITSA with FERC on October 21, 2011 in Docket No. ER12-167-000. The Commission accepted the NITSA for filing by a delegated letter order issued December 7, 2011.

May 31, 2013 and replace it with a new NITSA, a copy of which attached to this letter, to provide for service to EKPC loads under an EKPC Zonal NITSA.

C. Initial Allocation of Financial Transmission Rights for the EKPC Zone for the period June 1, 2013 to May 31, 2014.

D. Submission by EKPC of its Reactive Support Service revenue requirement to be incorporated by PJM into the applicable Schedule 2 Reactive Support Service rate schedule.

IV. Additional Information

A. Proposed Effective Date of June 1, 2013.

PJM and EKPC request an effective date of June 1, 2013 for the rates, terms and conditions for transmission service that are described in the tariff leaves that are filed herewith. In addition, PJM and EKPC request that the Commission issue an order on this submission by May 27, 2013, which is the first business day falling 60 days after this filing. Commission action by this date will provide PJM and EKPC with the certainty necessary for them to complete EKPC's integration into PJM by June 1, 2013.

B. Communications

Please place the names of the following persons on the official service list established by the Secretary in this proceeding:[56]

For PJM

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[56] PJM and EKPC request waiver of 18 CFR § 385.2010(i) to the extent necessary to include more than two names on the official service list.

For EKPC

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C. Part 35 Filing Requirements

As noted above, because it is a rural electric cooperative, EKPC is not subject to the Commission's regulations and it does not file a FERC Form 1. With respect to the EKPC rate formula, EKPC believes that the information contained in this filing provides sufficient information for the Commission to find that inclusion of EKPC's rate formula in the PJM Tariff is just and reasonable. EKPC has made every effort to present its information in a manner consistent with the Commission's ratemaking criteria. However, to the extent necessary, EKPC respectfully requests waiver of the part 35 of the Commission's filing requirements.

D. List of Documents Submitted With Filing

Together with this filing letter, PJM and EKPC submit the revised and new sections of the PJM Tariff, PJM OA, PJM RAA and PJM CTOA (Attachments A and B in marked and clean formats, respectively), the new PJM Service Agreements in clean format only (Attachments B), the Testimony and Exhibits of Ms. Ann Wood and Mr. Daniel Cooper on behalf of EKPC (Attachment C), a populated formula rate and supporting work papers (Attachment D) and the EKPC signature page to the CTOA (Attachment E).

Attachments A (redline) and B (clean)

PJM Tariff

- OATT Schedule 1A
- OATT Schedule 7
- OATT Schedule 8
- OATT Schedule 10-NERC
- OATT Schedule 10-RFC
- OATT Attachment C-1
- OATT Attachment C-3 (new)
- OATT Attachment H-24[57]
- OATT Attachment H-24A
- OATT Attachment H-24A Appendix A
- OATT Attachment H-24A Appendix B
- OATT Attachment H-24A Appendix C
- OATT Attachment H-24A Appendix D
- OATT Attachment H-24B
- OATT Attachment J[58]
- OATT Attachment K – Appendix, Section 3.2.2(q)
- OATT Attachment K – Appendix, Section 7.4.2(b)
- OATT Attachment L
- OATT Attachment DD, Section 5.10

PJM Operating Agreement

- OA Schedule 1, section 3.2.2(q)
- OA Schedule 1, section 7.4.2(b)
- OA Schedule 12

PJM RAA

- RAA Schedule 10.1
- RAA Schedule 15[59]

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[57] For new tariff language in items 4, 15 and 20, PJM and EKPC request waiver of the Commission's regulations which would require the submission of marked tariff revisions.

[58] Revisions adding the EKPC Zone to the map are not marked due to technical limitations. PJM requests a waiver of the Commission's regulations which would require the submission of marked tariff revisions for the revised map this tariff section.

[59] Revisions adding the EKPC Zone to the map are not marked due to technical limitations. PJM requests a waiver of the Commission's regulations which would require the submission of marked tariff revisions for the revised map in this tariff section.

RAA Schedule 17

PJM CTOA

TOA Attachment A

PJM Service Agreements (not in Attachment A)

EKPC - PJM Service Agreement No. 3517 - EKPC

LGE/KU - PJM Service Agreement No. 3518 – LGE/KU

Attachment C

Testimony

Testimony of Ms. Ann Wood (Exh. EKP-1)

Testimony of Mr. Daniel Cooper (Exh. EKP-2)

Attachment D

Populated Formula Rate (Exh. EKP-3)

Attachment H-24A

Attachment H-24A Appendix A

Attachment H-24A Appendix B

Attachment H-24A Appendix C

Attachment H-24A Appendix D

Attachment H-24A Supporting Exhibit

Attachment H-24B – Protocols

Attachment E

EKPC Signature Page to CTOA (Exh. EKP-4)

E. Service

PJM has served a copy of this filing on all EKPC existing customers, PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically.

In accordance with the Commission's regulations,[60] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[61] alerting them that this filing has

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[60] *See* 18C.F.R §§ 35.2(e) and 385.2010(f)(3)(2012).

[61] PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

Please contact the undersigned if you have any questions.

Respectfully submitted,

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Counsel to East Kentucky Power Cooperative, Inc.

Attachment A

Revisions to the
PJM Open Access Transmission Tariff,
PJM Operating Agreement,
PJM Reliability Assurance Agreement
and
PJM Consolidated Transmission Owners Agreement

(Identified by Additional Cover Pages)

(Marked / Redline Format)

Section(s) of the PJM Open Access Transmission Tariff

(Marked / Redline Format)

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

Zone	**Rate ($/MWh)**
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	0.0796
Metropolitan Edison Company	0.0796
Pennsylvania Electric Company	0.0796
Rockland Electric Company	0.2475
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company[1]	0.0797
Duquesne Light Company	0.0520
American Transmission Systems, Incorporated ("ATSI")	Rate updated annually Per Attachment H-21
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	Rate updated annually Per Attachment H-22
East Kentucky Power Cooperative, Inc. ("EKPC")	Per Attachment H-24

[1] Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$.0912//MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	1.41
Baltimore Gas and Electric Company	2.28
Delmarva Power & Light Company	2.17
PECO Energy Company	7.57
PP&L, Inc. Group	3.88
Potomac Electric Power Company	0.92
Public Service Electric and Gas Company	7.55
Jersey Central Power & Light Company	3.71
Metropolitan Edison Company	1.22
Pennsylvania Electric Company	1.90
Rockland Electric Company	0.57
Commonwealth Edison Company	41.42
AEP East Operating Companies	14.56
The Dayton Power and Light Company	2.41
Duquesne Light Company	1.20
American Transmission Systems, Incorporated ("ATSI")	3.05
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	4.17[2]
East Kentucky Power Cooperative, Inc. ("EKPC")	0.0

[2] Any change to this share must be made as a tariff filing under Section 205 of the Federal Power Act.

SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point
Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	32.114	2.676	0.6176	0.1235	0.0882
ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone[5/]	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone[6/]					
ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse PJMSettlement for any amounts payable as sales, excise, "Btu," carbon, value-added or similar

taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of $3.60/kw/year, $0.30/kw/mo., $0.0692/kw/week, $0.0099/kw/day-off-peak, or $0.0138/kw/day-on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 8
Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily On-Peak[1/] Charge ($/kW)	Daily Off-Peak[2/] Charge ($/kW)	Hourly On-Peak[3/] Charge ($/MWh)	Hourly Off-Peak[4/] Charge ($/MWh)
Border of PJM	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE Zone	1.984	0.4580	0.0920	0.0650	5.7	2.72
BG&E Zone	1.306	0.3010	0.0600	0.0430	3.8	1.80
Delmarva Zone	1.615	0.3730	0.0750	0.0530	4.6	2.21
JCPL Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
MetEd Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
Penelec Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
PECO Zone	2.189	0.5051	0.1010	0.0722	6.3	3.01
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *	PPL: * AEC: 0.11 UGI: *	PPL: * AEC: 0.05 UGI: *
Pepco Zone	1.750	0.4040	0.0810	0.0580	5.0	2.40
PSE&G Zone	1.975	0.4557	0.0911	0.0651	5.7	2.71
AP Zone	1.737	0.4009	0.0802	0.0573	5.0	2.39
Rockland Zone	2.676	0.6176	0.1235	0.0882	7.7	3.67
ComEd Zone[5/]	[6/]					

* PPL Electric Utilities Corporation’s and UGI Utilities’ respective component of the total charge is posted on the PJM Internet website.

AEP East Zone[7/] Nov. 1, 2005 SECA Ended W-JF Line In	AEP East Zone[7/]	Rate Pursuant to Attachment H-14	Monthly Charge X 12 / 52 ~~0.24948~~	Weekly Charge / 5	Weekly Charge / 7	Daily On-Peak Charge / 16
Dayton Zone	Dayton Zone	1.306	0.3014	0.0603	0.0431	3.77
Duquesne Zone	Duquesne Zone	1.18	0.27	0.0540	0.0386	3.38
Dominion Zone[8/]	Dominion Zone[8/]					
ATSI Zone	ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

1/ Monday - Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ 7:00 a.m. up to the hour ending 11:00 p.m.

4/ 11:00 p.m. up to the hour ending 7:00 a.m.

5/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 9 below to determine the actual charge to the Transmission Customer.

6/ The charges for the ComEd zone are posted on PJM's website. In addition to the other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:
Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;
Monthly Rate - $/kW/month. = Annual Rate divided by 12;
Weekly Rate - $/kW/week = Annual Rate divided by 52;
Daily rate - $/kW/day = Weekly Rate divided by 5.
In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be

needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

7/ The rates for non-firm point-to-point transmission service in the AEP Zone will be charged at the monthly, weekly, daily or hourly rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount, ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 8 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

8/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Monthly Charge - $/kW/month = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 12 divided by 1000 kW/MW;

Weekly Charge - $/kW/week = 12 times Monthly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7;

Hourly On-Peak Charge - $/MWh = Daily On-Peak Charge / 16 hours *1000 kW/ MW;

Hourly Off-Peak Charge - $/ MWh = Daily Off-Peak Charge / 24 hours *1000 kW/ MW.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery or Daily Off-Peak Delivery, shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion, Losses and Capacity Export:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion charges. If the Transmission Customer so elects, it shall either (a) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is positive, pay the higher of the applicable Transmission Congestion Charge or the applicable rate under section (1) above, or (b) if the

applicable Transmission Congestion Charge as calculated pursuant to Attachment K is negative, pay or be credited the sum of the applicable Transmission Congestion Charge and the rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay for any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

7) **Transmission Enhancement Charges:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd’s share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment (“SECA”) revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer’s bill in that month for service under this schedule.

9) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 10-NERC
North American Electric Reliability Corporation Charge

a) The North American Electric Reliability Corporation (NERC) is the Electric Reliability Organization (ERO) certified by the Federal Energy Regulatory Commission. Its purpose is to ensure the reliability of the interconnected bulk power system. This schedule will recover a share of NERC's costs of operations as set forth below.

b) PJM will charge each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the NERC Rate times the total quantity in MWhs of energy delivered to the load (including losses) that such customer serves in the PJM Region, excluding the Dominion Zone~~ and~~, the ATSI Zone and the EKPC Zone during such month. The exclusion applicable to the ATSI Zone shall expire on January 1, 2012.

c) A fixed rate will be charged for the first eleven billing periods of the current year. During the final billing period, a true-up component will be applied to adjust for any under or over collections for the current year.

d) NERC will submit final estimated costs to be recovered under this Schedule 10-NERC, determinants, and rates to the Transmission Provider no later than September 30th for the next calendar year. The Transmission Provider will post the rates for both components for the next calendar year no later than October 31st of the current year.

e) The NERCR shall be calculated each year in accordance with the formula:

$$NERCR = \frac{CYNC}{PJMNTHL}$$

where:

NERCR is the NERC Rate.

CYNC is the Current Year NERC Charges. These charges are the FERC approved funding for NERC for the year for which NERCR is being calculated. In the final billing for each calendar year a true-up component will be included applying any credit or deficiencies for the current year based on NERC's actual revenues as compared to NERC's FERC approved funding received under the schedule for the current year.

The Transmission Provider's NERC Total Hourly Load (PJMNTHL) is the estimated total quantity in MWhs of energy to be delivered to load (including losses) in the PJM Region, less the total quantity in MWhs of energy to be delivered to load (including losses) in the Dominion Zone, under Network Integration and Point-to-Point Transmission Service by all customers during the year for which NERCR is being calculated.

f) NERC is responsible for pursuing any and all defaults under this Schedule 10-NERC. Thus, the Transmission Provider will not deem any customer in default under the tariff for failure to pay any charges under this Schedule 10-NERC.

SCHEDULE 10-RFC
Reliability First Corporation Charge

a) Reliability*First* Corporation (RFC) is one of the Regional Entities of NERC. Its purpose is to ensure the reliability of the interconnected bulk power system. This schedule will recover RFC's statutory costs of operations as set forth below.

b) PJM will charge each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the RFC Rate times the total quantity in MWhs of energy delivered to load (including losses) that such customer serves in the PJM Region, excluding the Dominion Zone, ~~and~~ the ATSI Zone~~,~~ and the EKPC Zone, during such month. The exclusion applicable to the ATSI Zone shall expire on January 1, 2012.

c) A fixed rate will be charged for the first eleven billing periods of the current year. During the final billing period, a true-up component will be applied to adjust for any under or over collections for the current year.

d) NERC will submit final estimated costs to be recovered under this Schedule 10-RFC, determinants, and rates to the Transmission Provider no later than September 30th for the next calendar year. The Transmission Provider will post the rates for both components for the next calendar year no later than October 31st of the current year.

e) The RFCR shall be calculated each year in accordance with the formula:

$$RFCR = \frac{CYRC}{PJMRTHL}$$

where:

RFCR is the RFC Rate.

CYRC is the Current Year RFC Charges. These charges are the FERC approved funding for RFC for the year for which RFCR is being calculated. In the final billing for each calendar year a true-up component will be included applying any credit or deficiencies for the current year based on RFC's actual revenues as compared to RFC's FERC approved funding received under the schedule for the current year.

The Transmission Provider's RFC Total Hourly Load (PJMRTHL) is the estimated total quantity in MWhs of energy to be delivered to load (including losses) in the PJM Region, less the total quantity in MWhs of energy to be delivered to load (including losses) in the Dominion Zone, under Network Integration and Point-to-Point Transmission Service by all customers during the year for which RFCR is being calculated.

f) RFC is responsible for pursuing any and all defaults under this Schedule 10-RFC. Thus, the Transmission Provider will not deem any customer in default under the tariff for failure to pay any charges under this Schedule 10-RFC.

ATTACHMENT C-3

Conversion of Service in the EKPC Zone

The Office of the Interconnection is scheduled to become the Transmission provider for the EKPC Zone under the terms of this Tariff on June 1, 2013 and the EKPC tariff shall be superseded with respect to the EKPC Zone. Reservations purchased on the EKPC OASIS nodes prior to the integration of the EKPC Zone which remain in place following the integration date shall be converted to the appropriate service under this Tariff and subject to the rates, terms and conditions of this Tariff. In addition, interconnection requests under the EKPC tariff pending prior to the integration of the EKPC Zone shall be converted to requests for interconnection under this Tariff. This Attachment sets forth the principles that shall govern such conversions of service.

Customers who have reservations that need to be converted will be contacted directly by the Office of the Interconnection. Not all transmission service provided under the EKPC tariff exactly matches a service under this Tariff. Differences include variations in product definitions and PJM Region LMP pricing points. These variances in transmission requests will be converted into the defined product types explained below. The guidelines for the conversion of service are as follows:

1. All existing reservations will retain the same capacity (in megawatts) and will be converted to a comparable PJM product and duration with the applicable point of receipt, point of delivery and path. Firm Point-to-Point Transmission Service redirected on a non-firm basis to Secondary Receipt or Delivery Points under the EKPC tariff prior to the EKPC integration date will be converted to service under this Tariff on the basis of the original firm points of receipt and delivery. Firm Point-to-Point Transmission Service redirected on a firm basis under section 22.2 (Modification on a Firm Basis) (or equivalent) of the EKPC tariff prior to the EKPC integration date will be converted to service under this Tariff on the basis of the modified firm points of receipt and delivery.

2. All EKPC reservations extending past the integration date must select Source and Sink LMP pricing points corresponding to the appropriate interface, where applicable, willing to pay through (or not), a new product if applicable. Willing to pay congestion (or not) must be determined no later than 12:00 noon EPT, 30 days prior to the EKPC integration start date. In the event the customer does not choose within the allotted deadline above, PJM will convert the service to the most closely analogous service under the PJM Tariff, in PJM's judgment. Willing to pay congestion is optional for non-firm and non-designated transmission service; Firm service, by definition, is willing to pay congestion. All converted service (as they exist) will be placed on the PJM OASIS no later than 30 days prior to the EKPC integration start date.

3. All EKPC import reservations will be converted to one of the following service types as defined by this Tariff or on the PJM OASIS. Spot market, Non-Firm Point-to-Point, Network Designated or Network Non-Designated. This choice will be made on an individual reservation basis, based on the scheduling intent of the reservation.

4. All existing EKPC Zone extended transmission requests (*i.e.* monthly, weekly, daily) that span multiple months will be converted to their largest individual components as defined on the PJM OASIS. For example, a monthly request from October 1 to December 1 will be converted to two individual monthly requests, October 1 to November 1, and November 1 to December 1; and daily request from January 1 of one year to January 1 of the next year will be converted to yearly service.

5. Sliding monthly service (*i.e.*, monthly service that does not run from the first day of the given month to the last day of the given month) will be converted to weekly and daily service.

6. Sliding weekly service (*i.e.*, weekly service that does not run from Monday at 00:00 to Sunday at 23:59) will be converted to daily service.

7. Transmission service that is not currently confirmed on the EKPC OASIS nodes and is in active status such as "Received," "Queued" or "Study" will be transferred to the integrated PJM OASIS node and will maintain its initial queued date.

8. All "Grandfathered" requests that exist on the EKPC OASIS nodes will require a reservation on the PJM OASIS node.

9. To facilitate the OASIS transition, from one month prior to the respective integration start date until such integration start date, requests for service that are active on or after such date one month prior to the integration start date should be made on both the pre-integration transmission owner or OASIS nodes and the PJM OASIS nodes.

10. Reservations will be converted based on the priority of the product.

11. Although the Office of the Interconnection will attempt to convert existing transmission reservations into comparable reservations on the PJM OASIS, there will be unique instances where this will not be possible (*e.g.*, reliability issues, etc.). In this case, reservations will be reviewed on a case-by-case basis. Transmission service that is not currently accepted on the EKPC Zone OASIS nodes and is in active state such as "Received," "Queued" or "Study" will be assigned the same status and queue position on the PJM OASIS as it had on the EKPC OASIS prior to conversion.

12 Converted Point-to-Point and Network transmission service reservations that extend beyond or begin after the integration commencement date will be posted to the PJM

OASIS web page on an as-needed basis. The web page will identify the original EKPC Zone reservation and the new PJM OASIS reservation.

13. An Interconnection Request pending under the EKPC tariff at the time of the integration of the EKPC Zone shall be assigned the same priority date under this Tariff as such request had under the EKPC tariff immediately prior to such integration. The Interconnection Request will be assigned a PJM queue identifier such that the Interconnection Customer's priority date relative to existing PJM queued Interconnection Requests can be easily determined. All such Interconnection Requests will be integrated into PJM's existing Interconnection Queue(s), effective on the EKPC integration start date, and will be subject to the generation interconnection procedures under Parts IV and VI of this Tariff. On the EKPC integration date, PJM will assume the technical studies that have been started under the EKPC tariff. After the studies are complete, the Interconnection Customer will be required to pay for any Network Upgrades and/or Local Upgrades that are needed for the generating unit to qualify for Capacity Interconnection Rights under this Tariff.

ATTACHMENT H-24
Annual Transmission Rates – EKPC
for Network Integration Transmission Service
and Point-to-Point Transmission Service

1. The Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service and Point-to-Point Transmission Service are the product of the formula shown in Attachment H-24A, and will be posted on the PJM website. The ATRR and the rates reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of East Kentucky Power Cooperative, Inc. ("EKPC").

2. The formula rate in this attachment shall be effective until amended by EKPC or modified by the Commission.

3. EKPC and American Electric Power shall be subject to the additional provisions of PJM Service Agreement No. 1530, Composite Interconnection Agreement between American Electric Power Service Corporation and East Kentucky Power Cooperative.

4. EKPC and Louisville Gas & Electric Company/Kentucky Utilities Company shall be subject to the additional provisions of PJM Service Agreement No. 3518, Service Agreement For Network Integration Transmission Service among PJM Interconnection, L.L.C., PJM Settlement Inc. and Louisville Gas and Electric Company/Kentucky Utilities Company.

Formula Rate - Non-Levelized — For the 12 months ended 12/31/20__

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 0
	REVENUE CREDITS	Note A	Total	Allocator		
2	Account No. 454	(page 4, line 34)	$ 0	TP	0.00000	$ 0
3	Account No. 456.1 (Net of Revenues from Grandfathered Transactions)	(page 4, line 35)	0	TP	0.00000	138,871
4	Revenues from Grandfathered Transactions	Note B	0	TP	0.00000	155,395
5	Revenues from service provided by the ISO at a discount		0	TP	0.00000	0
5a	Transmission Enhancement Credit		0	TP	0.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5b)					$ 0
6a	True-up Adjustment	Note C				$ -
7	NET REVENUE REQUIREMENT	(line 1 minus line 6 plus line 6a)				$ 0
	DIVISOR					
8	1 CP	Note D				0
9	12 CP	Note E				0
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$ 0.000			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$0.000			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.000			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$0.000			
			On-Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.000			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.000	Capped at weekly rate		$0.000
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.000	Capped at weekly and daily rate		$0.000

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.	(1) RATE BASE	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	204.46.g	$ 0	NA		
2	Transmission	206.58.g	0	TP	0.00000	$ 0
3	Distribution	206.75.g	0	NA		
4	General & Intangible	204.5.g & 206.90.g	0	W/S	0.00000	0
5	Common		0	CE	0.00000	0
6	TOTAL GROSS PLANT(sum lines1-5)		$ 0	GP=	0.000%	$ 0
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 0	NA		
8	Transmission	219.25.c	0	TP	0.00000	$ 0
9	Distribution	219.26.c	0	NA		
10	General & Intangible	219.28.c	0	W/S	0.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 0			$ 0
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 0			
14	Transmission	(line 2 - line 8)	0			$ 0
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	0			0
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		$ 0	NP=	0.000%	$ 0
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	272.Total 281.k	$ -	NA	zero	$ -
20	Account No. 282 (enter negative)	274.Total 282.k	0	NP	0.00000	0
21	Account No. 283 (enter negative)	276.Total 283.k	0	NP	0.00000	0
22	Account No. 190	234.Total 190.c	0	NP	0.00000	0
23	Account No. 255 (enter negative)	266.Total.h	0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19-23)		$ 0			$ 0
25	LAND HELD FOR FUTURE USE	214.Total.d, Note F	$ -		0.00000	$ -
	WORKING CAPITAL					
26	CWC	calculated, Note G	$ 0			0
27	Materials & Supplies	227.8.c	0	TE	0.00000	0
28	Prepayments (Account 165)	110.46.c, Note G	0	GP	0.00000	0
29	TOTAL WORKING CAPITAL (sum lines 26-28)		$ 0			$ 0
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 0			$ 0

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.100	$ 0	TE	0.00000	$ 0
2	Less Account 565	321.Acct 565	0	TE	0.00000	0
3	A&G	321.168	0	W/S	0.00000	0
4	Less FERC Annual Fees	N/A	0	W/S	0.00000	0
5	Less Non-safety Advertising	Note H	0	W/S	0.00000	0
5a	Less KPSC Regulatory Expenses	Note H	0			0
5b	Plus Transmission Related Regulatory Exp	Note H	0	TE	0.00000	0
5c	Plus Prorated PJM Transition Expense	Note H	0			0
6	Common		0	CE	0.00000	0
7	Transmission Lease Payments		0		0.00000	0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6,7 less lines 1a, 2, 4, 5)		$ 0			$ 0
	DEPRECIATION EXPENSE					
9	Transmission	336.7.f	$ 0	TP	0.00000	$ 0
10	General and Intangible	336.9.f	0	W/S	0.00000	0
11	Common	336.10.f	0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9-11)		$ 0			$ 0
	TAXES OTHER THAN INCOME TAXES					
	LABOR RELATED					
13	Payroll	Note I	$ 0	W/S	0.00000	$ 0
14	Highway and vehicle	Note I	0	W/S	0.00000	0
15	PLANT RELATED					
16	Property	Note I	0	GP	0.00000	0
17	Gross Receipts		0	NA	NA	0
18	Other		0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (sum lines 13-19)		$ 0			$ 0
	INCOME TAXES	Note J				
21	T=1 - {[(1-SIT) * (1-FIT)] / (1 - SIT * FIT * p)} =		0.000000%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.000000%			
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	0			
25	Income Tax Calculation (line 22 * line 28)		$ 0	NA		$ 0
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0
27	Total Income Taxes	(line 25 plus line 26)	$ 0			$ 0
28	RETURN					
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 29)]		$ 0	NA		$ 0
29	REVENUE REQUIREMENT (sum lines 8,12, 20, 27, 28)		$ 0			$ 0

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.						
	TRANSMISSION PLANT INCLUDED IN ISO RATES					
1	Total transmission plant (page 2, line 2, column 3)					0
2	Less transmission plant excluded from ISO rates					0
3	Less transmission plant included in OATT Ancillary Services	See Supporting Exhibit, Page 5 of 8, Line 4, (Note K)				0
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)					0
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)				TP=	0.00000
	TRANSMISSION EXPENSES					
6	Total transmission expenses (page 3, line 1, column 3)					0
7	Less transmission expenses included in OATT Ancillary Services	Note L				0
8	Included transmission expenses (line 6 less line 7)					0
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)					0.00000
10	Percentage of transmission plant included in ISO Rates (line 5)				TP	0.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)				TE=	0.00000

Line No.		Form 1 Reference	$	TP	Allocation		
	WAGES & SALARY ALLOCATOR (W&S)						
12	Production	354.18.b	0	0.00	0		
13	Transmission	354.19.b	0	0.00	0		
14	Distribution	354.20.b	0	0.00	0		W&S Allocator
15	Other	354.21,22,23,24.b	0	0.00	0		($ / Allocation)
16	Total (sum lines 12-15)		0		0	=	0.00000

Line No.			%		% Electric		W&S Allocator
	COMMON PLANT ALLOCATOR (CE)						
17	Electric	200.3.c	0.00		(line 17 / line 20)		(line 16)
18	Gas	201.3.d	0.00		0.00000	*	0.00000
19	Water	201.3.e	0.00				
20	Total (sum lines 17 - 19)		0.00				

Line No.				$
	RETURN (R)			
21		Long Term Interest (117, sum of 58.c through 65.c)		0
22		Preferred Dividends (118.29c) (positive number)		0
	Development of Cost of Capital:			
23	Long Term Debt	(112.23c) See Supporting Exhibit, Page 7 of 8		$ 0
24	Proprietary Capital	(112.15.c)		0
25	Less Account 216.1	(112.12.c) (enter negative)		0
26		Total Capital	(sum lines 23-25)	$ 0

Line No.			$	%	Cost		Weighted
27	Long Term Debt (112.23c)	Note M	0	0.00%	0.000%		0.000%
28	Proprietary Capital (112.15.c)	Note N	0	0.00%	**0.000%**		0.000%
29	Total (sum lines 27-28)		0		**R =**		**0.000%**
30	Effective TIER	Note O			**TIER =**		**0.00**

Line No.				
	REVENUE CREDITS			
	ACCOUNT 447 (BUNDLED SALES FOR RESALE)		(310-311)	
31	a. Bundled Non-RQ Sales for Resale (311.x.k)			$ 0
32	b. Bundled Sales for Resale included in Divisor on page 1			0
33	Total of (a)-(b)			$ 0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	See Supporting Exhibit, Page 6 of 8, Line 3 (Note P)		$ 0
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)	See Supporting Exhibit, Page 6 of 8, Line 17 (Note Q)		$ 0

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

General Note: **References to pages in this formulary rate are indicated as: (page#, line#, col.#)**
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Formulary Rate Template.
B	Revenue from AEP Grandfathered Agreement. See Rev Cred Support, Attachment H-24A, Supporting Exhibit, page 6 of 8, line 16
C	Calculated in accordance with the EKPC Formulary Rate Protocols in Attachment H-24B of this Tariff. See Appendix C
D	EKPC 1 CP is EKPC's highest Monthly Firm Transmission System Peak Load based on the source data as described in Note 1 of Attachment H-24A, Page 8 of 8, plus transmission service provided for others over the EKPC transmission system, plus wheel-out to EKPC load connected to AEP/KP, Duke Ky, and LGE/KU See Attachment H-24A, Supporting Exhibit, Page 8 of 8
E	EKPC 12 CP is EKPC's Monthly Firm Transmission System Peak Load based on the source data as described in Note 1 of Attachment H-24A, Page 8 of 8, plus transmission service provided for others over the EKPC transmission system, plus wheel-out to EKPC load connected to AEP/KP, Duke Ky, and LGE/KU See Attachment H-24A, Supporting Exhibit, Page 8 of 8
F	Identified in EKPC Form FF1 as being non-transmission related. See Attachment H-24A, Supporting Exhibit, Pg 2 of 8
G	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3 of 5, line 8, column 5.
	Prepayments are the electric related prepayments booked to Account No. 165 and reported on EKPC Form FF1, Ref Pg 110, line 46.
H	Line 5 - Remove non-safety related advertising included in Account 930.1. See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 3
	Line 5a - Remove Total Regulatory Commission Expenses - See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 4
	Line 5b - Add Back Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting - See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 6
	Line 5c - Add EKPC costs relating to PJM transition. See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 14
I	In accordance with RUS accounting standards, EKPC allocates all payroll and property taxes to the functional account. Labor- and plant-related taxes are already included in the appropriate transmission account.
J	As a member-owned non-profit RUS generation and transmission cooperative, EKPC is exempt from state and from federal income taxes under 501(c)(12) of Internal Revenue Code
K	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, included in Account 561. See Attachment H-24A, Supporting Exhibit, Page 4 of 8.
M	Debt cost rate = long-term interest (line 21) / long term debt (line 27).
N	Proprietary Capital Cost calculated to achieve TIER of 1.50
O	TIER value approved by KPSC in Case No. 2010-000167
P	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
Q	Net of retained legacy transactions. See Attachment H-24A, Supporting Exhibit, page 6 of 8.

East Kentucky Power Cooperative, Inc.
Transmission Formula Rate Revenue Requirement
Utilizing EKPC 20__ Form FF1 Data
For Rates Effective June 1, 20__

Schedule 1A Rate Calculation

	Line No.		Source	Revenue Requirement	
A.		Schedule 1A Annual Revenue Requirements			
	1	Total Load Dispatch & Scheduling (Account 561)	Supporting Exh, page 4 of 8, line 11	$ 0	
		Less allocated amount for steam production [(Line 6c/Line 6b) * Line 1]		$ 0	
		Total Load Dispatch & Scheduling (Account 561) excluding Steam		$ 0	
	2	Revenue Credits for Schedule 1A	Note 1	$ -	
	3	Net Schedule 1A Revenue Requirement for Zone		$ 0	
	4	Less: True Up Under/(Over) Recovery for 12 months ended 12/31/20__	Note 2	$ -	
	5	Schedule 1A Recovery Amount for 12 Months ended		$ 0	
B.		Schedule 1A Rate Calculations	Note 3		
	6	2012 Requirements Sales for Resale	Note 4	0	MWh
	6a	Plus Non-requirements Sales for Resale	Note 5	0	
	6b	Subtotal	Note 6	0	
	6c	Less Equivalent Steam		0	
	6d	Net MWh		0	MWh
	7	Schedule 1A rate $/MWh (Line 5 / Line 6)	(Line 3 / Line 6)	$0.0000	$/MWh

Notes:

(1) Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of EKPC's zone during the year used to calculate rates under Attachment H-24A
(2) Amount from Attachment H-24A, Appendix C, line 13 for stated year.
(3) Sourced from EKPC Form FF1, Ref Pg 401, adjusted for equivalent steam sold
(4) FF1, Ref Page 401, Line 23
(5) FF1, Ref Page 401, Line 24
(6) FF1, Ref Page 401, Footnote

Rate Formula Template
Utilizing Attachment H-24A
East Kentucky Power Cooperative, Inc.
RTEP - Transmission Enhancement Charges
To be completed in conjunction with Attachment H-24A

	(1)	(2)	(3)	(4)
Line No.		Attachment H-24A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Attachment H-24A, p 2, line 2 col 5 (Note A)	0	
2	Net Transmission Plant - Total	Attachment H-24A, p 2, line 14 col 5 (Note B)	0	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attachment H-24A, p 3, line 8 col 5	0	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.00%	0.00%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attachment H-24A, p 3, lines 10 & 11, col 5 (Note H)	0	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.00%	0.00%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attachment H-24A, p 3, line 20 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.00%	0.00%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**0.00%**
	INCOME TAXES			
10	Total Income Taxes	Attachment H-24A, p 3, line 27 col 5	-	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	0.00%	0.00%
	RETURN			
12	Return on Rate Base	Attachment H-24A, p 3, line 28 col 5	25,293,160	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	6.58%	6.58%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**6.58%**

Note
A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-24A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-24A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-24A, page 3 line 12.
F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
G The Network Upgrade Charge is the value to be used in PJM OATT Schedule 26.
H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in Attachment H-24A Appendix B, page 2, column 9.

For the 12 months ended 12/31/20__

East Kentucky Power Cooperative, Inc.
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
					-			-		-		-
1a			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
					-			-		-		-
					-			-		-		-
					-			-		-		-
					-			-		-		-
					-			-		-		-
					-			-		-		-
					-			-		-		-
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-24A, Page 1, Line 5c											$0

Note Letter
- A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-24A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
- B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-24A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
- C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
- D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
- E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-24A, page 3 line 12.
- F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
- G The Network Upgrade Charge is the value to be used in Schedule 26.
- H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Rate Formula Template
Utilizing Attachment H-24A

East Kentucky Power Cooperative, Inc.
Calculation of Prior Year Transmission Revenue Requirement True-up Adjustment
To be completed in conjunction with Attachment H-24A

Line No.	(1)		(2)
	Reconciliation Adjustment for Transmission Revenue Requirements		
1	Actual Transmission Revenue Requirement for 12 Months Ended 12/31/20__ including True Up for 12 months ended 12/31/20__ (1)		$ -
2	Less: True Up Under/(Over) Recovery Adjustment for EKPC Appendix H-24A for 12 months ended 12/31/20__ (2)		$ -
3	Transmission revenue requirements for the 12 months ended12/31/20__	(Line 1 - Line 2)	$ -
4	Less: Actual Transmission Revenue Collected for 12 months Ended 12/31/20__ (3)		$ -
5	True-Up Principal Under(Over) Recovery before Interest	(Line 3 - Line 4)	$ -
6	Monthly Interest Rate--Final FERC rate (4)		0.000%
7	Number of Months being Trued Up		0
8	Interest	(Line 5 x Line 6 x Line 7)	$ -
9	True Up Principal & Interest Under(Over) Recovery--Preliminary (5)	(Line 9 + Line 15)	$ -

Notes:
(1) Revenue requirement from Page 1 of 5, line 7 of Attachment H-24A for the referenced year.
(2) EKPC Attachment H-24A, page 1 of 5, Line 6a for the referenced recovery year
(3) Revenue received under PJM Tariff Schedules 7 and 8 under Attachment H-24A for the referenced year.
(4) See: *http://www.ferc.gov/legal/acct-matts/interest-rates.asp* for the appropriate Month
(5) Goes to Attachment H-24A , page 1 of 5, line 6a

Rate Formula Template
Utilizing Attachment H-24A

East Kentucky Power Cooperative, Inc.
Calculation of Prior Year Transmission Revenue Requirement True-up Adjustment
To be completed in conjunction with Attachment H-24A

Line No.	(1)		(2)
	Reconciliation Adjustment for Schedule 1A Charges		
10	Actual Schedule 1A Costs for 12 Months Ended 12/31/20__ including True Up for 12 months ended 12/31/20__ (6)		$ -
11	Less: True Up Under/(Over) Recovery Adjustment for EKPC Sch. 1A for 12 months ended 12/31/20__ (7)		$ -
12	True-Up Principal Under(Over) Recovery before Interest	(Line 10 - Line 11)	$0.00
13	Less: Actual Sch. 1A Revenue Collected for 12 months Ended 12/31/20__ (8)		$0.00
14	True-Up Principal Under(Over) Recovery before Interest	(Line 12 - Line 13)	$ -
15	Monthly Interest Rate--Final FERC rate (9)		0.000%
16	Number of Months being Trued Up		0
17	Interest	(Line 5 x Line 6 x Line 7)	$ -
18	True Up Principal & Interest Under(Over) Recovery--Preliminary (10)	(Line 9 + Line 15)	$ -

Notes:
(6) Revenue requirement calculated using EKCP Attachment H-24A, Appendix A and actual cost information for the referenced year.
(7) EKPC Attachment H-24A, Appendix A, Line 6a for the referenced recovery year.
(8) Revenue received from PJM under PJM Tariff Schedules 7 and 8 for the EKPC Zone under Attachment H-24A for the referenced year.
(9) See: *http://www.ferc.gov/legal/acct-matts/interest-rates.asp* for the appropriate Month
10) Goes to Attachment H-24A, Appendix A, line 4.

East Kentucky Power Cooperative, Inc.
Depreciation Rates
Rates effective for year ending December 31, 20__

Line No.	FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D)
			Transmission Plant (1)	%
1	350	350010	Rights of Way (No depr on land)	-
2	353	353000	Station Equipment	0.000
3	353	353010	Station Equipment - ECS	0.000
4	354	354000	Towers and Fixtures - Trans Plant	0.000
5	355	355000	Poles & Fixtures	0.000
6	356	356000	Overhead Conductors & Devices	0.000
7	359	359000	Roads and Trails - Trans Plant	0.000
			General and Intangible Plant	
8	303	303000	Miscellaneous Intangible Plant	0.000
9	390	390000	Structures and Improvements - General Plant	0.000
10	391	391000	Office Furn & Equip - Gen Plant	0.000
11	391	391001	Office Furn & Equip - Peoplesoft	0.000
12	392	392000	Transportation Equipment	0.000
13	393	393000	Stores Equipment	0.000
14	394	394000	Tools, Shop & Garage Equipment	0.000
15	395	395000	Lab Equipment - General Plant	0.000
16	396	396000	Power Operated Equip - Gen Plant	0.000
17	397	397000	Communication Equipment - General Plant	0.000
18	397	397000	Communication Bldgs & Towers	0.000
19	397	397001	Communication Eq - ECS - General Plant	0.000
20	398	398000	Misc Equip - General Plant	0.000

NOTES:
(1) Depreciation Rates approved in KPSC Case No. ______________.

ATTACHMENT H-24B
EKPC FORMULA RATE IMPLEMENTATION PROTOCOLS[1]

DEFINITIONS

"Annual Transmission Revenue Requirements" means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.

"Annual Update" means the posting and informational filing submitted by EKPC on or before May15 of each year that sets forth the EKPC Cost of Service ("COS") for the subsequent Rate Year.

"Discovery Period" means the period after each annual Publication Date to serve information requests on EKPC as provided in these Protocols.

"First Rate Year" means the period that begins on June 1, 2013, and ends on May 31, 2014.

"Formal Challenge" means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission ("Commission") as provided in these Protocols.

"Formula Rate" means these Formula Rate Implementation Protocols (to be included as Attachment H-24B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.

"Formula Rate Template" means the collection of formulae and worksheets, unpopulated with any data, to be included as Attachment H-24A of the PJM Tariff.

"Preliminary Challenge" means a written challenge to the Annual Update submitted to EKPC as provided in these Protocols.

"Protocols" means these Formula Rate Implementation Protocols (to be included as Attachment H-24B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update.

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[1]East Kentucky Power Cooperative, Inc ("EKPC") is an electric cooperative with outstanding debt from the United States Rural Utilities Service, and is not a FERC-jurisdictional public utility as that term is used in the Federal Power Act, 18 U.S.C. 824(f). In submitting and complying with these procedures and the formula rate, EKPC is not waiving its non-jurisdictional status and is not submitting to the FERC's jurisdiction except to the extent that the

Commission by law has jurisdiction to review EKPC's rates by virtue of EKPC's participation in PJM.

SECTION 1 Annual Updates

a. Beginning with the First Rate Year and for each Rate Year thereafter, the Annual Transmission Revenue Requirement calculated in accordance with Attachment H-24A and the Network Integration Transmission Service and Point-to-Point rates derived from Attachment H-24A shall be applicable to transmission services provided by PJM for the EKPC transmission pricing zone during the Rate Year.

b. On or before April 30 of each year, EKPC shall recalculate its Annual Transmission Revenue Requirement, producing the "Annual Update" for the upcoming Rate Year. EKPC shall:

(i) Arrange for PJM to post such Annual Update on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) as both a .pdf (Portable Document Format) document and a fully-functioning Excel file;

(ii) Provide contact information for inquiries concerning the Annual Update;

(iii) Send an email or other similar electronic communication to all parties affected by the Annual Update or which have previously requested such notification through procedures to be established by EKPC, informing the recipients that the Annual Update is available and providing the Uniform Resource Locator or other similar identifying location information from which the Annual Update can be obtained.

c. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the Commission, then the posting shall be due on the next business day.

d. The date on which the Annual Update is posted shall be that year's Publication Date.

e. Within two business days of the Publication Date, EKPC shall arrange for PJM to provide notice on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) of the time, date and location of an open meeting among interested parties ("Annual Meeting"). This Annual Meeting shall (i) permit EKPC to explain and clarify its Annual Update and (ii) provide interested parties an opportunity to seek information and clarifications from EKPC about the Annual Update. The Annual Meeting shall take place no sooner than ten (10) days after posting of the notice and no later than thirty (30) days after the Publication Date.

f. Inputs to the Formula Rate are based on EKPC's financial records and supporting work papers, which reflect:

(i) The RUS's Uniform System of Accounts, and

(ii) Applicable EKPC Form FF1[2] as each exists as of the later of the date of EKPC's initial filing of the Formula Rate or the last day of the calendar year immediately preceding the effective date of the most recent revision to the Formula Rate.

[2] EKPC is not a Public Utility as that term is used under the Federal Power Act and is therefore does not prepare or file a FERC Form No. 1 with the Commission. However, EKPC annually prepares a report on its finances and expenses containing information that matches that required for the FERC Form No. 1 and files that document with the Kentucky Public Service Commission. That document is designated as the EKPC Form FF1.

g. The Annual Update for the Rate Year:

(i) Shall, to the extent specified in the Formula Rate, be based upon the EKPC Form FF1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of EKPC consistent with Section 1.f above;

(ii) Shall, to the extent specified in the Formula Rate, provide the Formula Rate calculations and all inputs thereto, as well as support for data not otherwise available in the EKPC Form FF1 that are used in the Formula Rate;

(iii) Shall describe material changes, if any, in EKPC's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based that could or do materially affect the charges under the Formula Rate;

(iv) Shall be subject to challenge and review in accordance with the procedures set forth in this Attachment H-24B as to the appropriateness of the input data and the application of the Formula Rate according to its terms and the procedures in this Attachment H-24B;

(v) Except as provided for in Section 1.j below, shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate (i.e., all such modifications to the Formula Rate will require a filing with the FERC).

h. Formula Rate inputs for the Times Interest Earned Rate (TIER) and depreciation rates shall be stated values until changed pursuant to a filing made effective by the Commission.

SECTION 2 Annual Review Procedures

Each Annual Update shall be subject to the following Annual Review Procedures:

a. Interested parties shall have up to one hundred fifty (150) days after the Publication Date to review the inputs, supporting explanations, allocations and calculations ("Review

Period") and to notify EKPC in writing, which notification may be made electronically, of any specific challenges.

b. Interested Parties shall have up to one hundred twenty (120) days after each annual Publication Date to serve reasonable information requests on EKPC. Such information requests shall be limited to what is necessary to determine if EKPC has properly applied the Formula Rate and the procedures of this Attachment H-24B Formula.

c. EKPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests.

d. Preliminary Challenges shall be subject to the resolution procedures and limitations in Section 3. Formal Challenges shall be filed pursuant to these Protocols and shall include the information required under 18 C.F.R. § 385.206 (b) (1), (2), (3), (4), and (7).

e. Preliminary or Formal Challenges related to material changes are not intended to serve as a means of pursuing other objections to the Formula Rate. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.

SECTION 3 Resolution of Challenges

a. If EKPC and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of EKPC to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the Commission, which shall be served on EKPC by electronic service on the date of such filing.

b. In any proceeding initiated by the Commission concerning the Annual Update or in response to a Formal Challenge, EKPC shall bear the burden of proving that it has correctly applied the terms of the Formula Rate.

c. Each Annual Update shall become final as to the Annual Transmission Revenue Requirement calculated for the Rate Year for which the Annual Update was calculated and no longer subject to challenge pursuant to these Protocols on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and the Commission has not initiated a proceeding to consider the Annual Update, or (ii) a final Commission order issued in response to a Formal Challenge or a proceeding initiated by the Commission to consider the Annual Update.

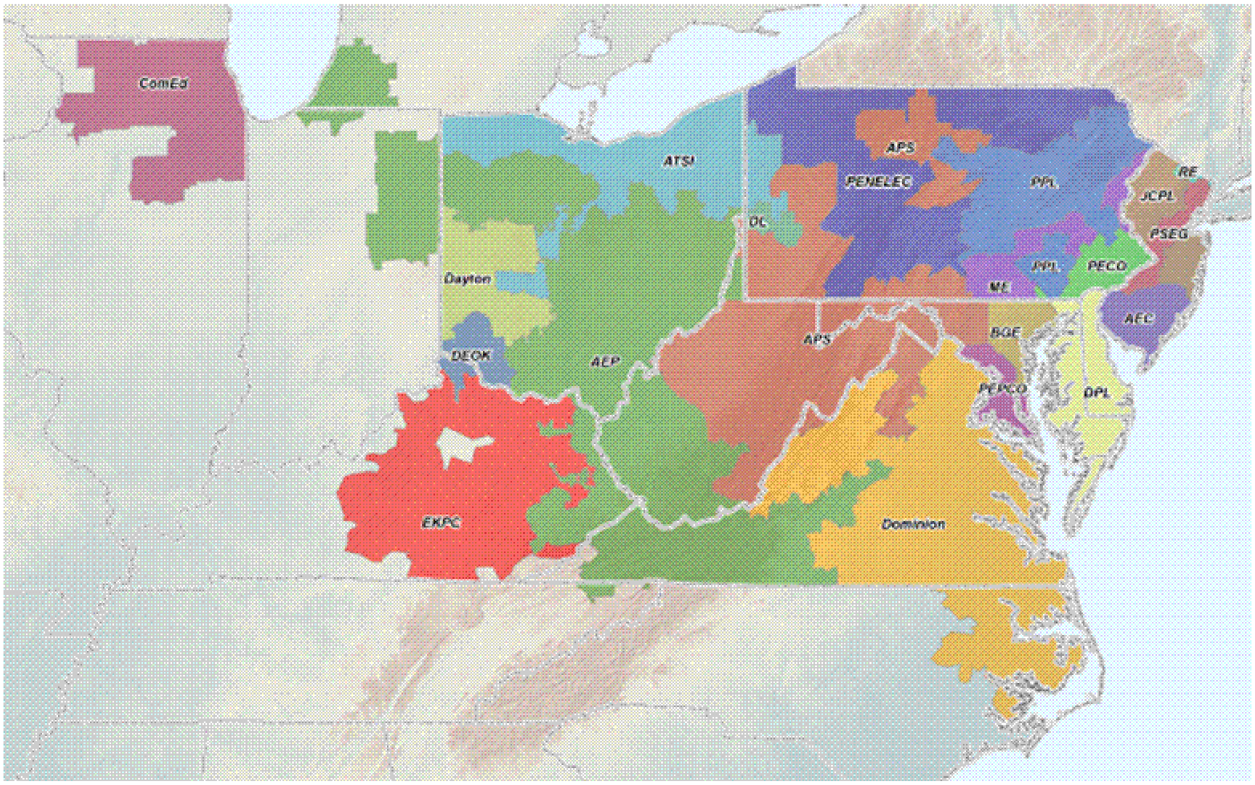
d. Except as specifically provided herein, nothing shall be deemed to limit in any way the right of EKPC to unilaterally file changes to the Formula Rate or any of its inputs (including, but not limited to, TIER or a replacement for TIER, transmission depreciation rates and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. These Protocols in no way limit the rights of EKPC or any Interested Party to initiate a proceeding at the Commission at any time with respect to the Formula Rate or any Annual Update consistent with the party's full rights under the FPA.

SECTION 4 Changes to Annual Informational Filings

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's EKPC Form FF1, or input data used for a Rate Year or calendar year that would have affected the Annual Update for that Rate Year or calendar year, or as the result of any Commission proceeding to consider a prior year's Annual Update, EKPC shall promptly notify the interested parties and provide a copy of the revised Annual Update to PJM for posting on the PJM's web site.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest.

ATTACHMENT J
PJM Transmission Zones



FULL NAME	SHORT NAME
Pennsylvania Electric Company	PENELEC
Allegheny Power	APS
PPL Electric Utilities Corporation	PPL
Metropolitan Edison Company	ME
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
Duquesne Light Company	DL
Virginia Electric and Power Company	Dominion
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK
East Kentucky Power Cooperative, Inc.	EKPC

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

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

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

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

3.2.2 Regulation.

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

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying* the assigned MW(s) by the performance Regulation market-clearing price, *by* the *ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources*, and *by* the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

$$\text{Error} = \text{Average of Abs}\left((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})\right);\text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for

Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

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

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

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

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

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

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

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

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and
>
> where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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

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

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage.

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

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

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

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer

Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

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

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

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$\text{Ramp\_Request}_t = (\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}) / (\text{UDSLAtime}_{t-1})$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

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

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

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

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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

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

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

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. \$250/MWh for the 2012/2013 Delivery Year;

ii. \$400/MWh for the 2013/2014 Delivery Year;

iii. \$550/MWh for the 2014/2015 Delivery Year; and

iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-

Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non- Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the

Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

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

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the

Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

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

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

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

3.2.7 Billing.

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

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

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; 2013 for the EKPC Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each

historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Prior to the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights allocated at the aggregate load buses in a Zone. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section

7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Prior to the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights sink at the aggregate load buses in a Zone. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under

contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web

site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

ATTACHMENT L
List of Transmission Owners

Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Atlantic City Electric Company
Baltimore Gas and Electric Company
NAEA Rock Springs, LLC
Delmarva Power & Light Company
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
East Kentucky Power Cooperative, Inc.
Hudson Transmission Partners, LLC
Jersey Central Power & Light Company
Metropolitan Edison Company
Neptune Regional Transmission System, LLC
Old Dominion Electric Cooperative
Pennsylvania Electric Company
PECO Energy Company
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Trans-Allegheny Interstate Line Company
UGI Utilities, Inc.
Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power
Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.
The Dayton Power and Light Company
AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)
Duquesne Light Company
Virginia Electric and Power Company
Linden VFT, LLC
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Hamilton, OH

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target ; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency

Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2015, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $128,000 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	140,000
BGE, PEPCO ("CONE Area 2")	130,600
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC ("CONE Area 3")	127,500
PPL, MetEd, Penelec ("CONE Area 4")	134,500
Dominion ("CONE Area 5")	114,500

B) Beginning with the 2016-2017 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2015-2016 Delivery Year to which the Applicable H-W Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under

the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the Zone in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Section(s) of the
PJM Operating Agreement

(Marked / Redline Format)

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

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

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

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

3.2.2 Regulation.

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

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying* the assigned MW(s) by the performance Regulation market-clearing price, *by* the *ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources*, and *by* the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

$$\text{Error} = \text{Average of Abs}\left((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})\right); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the

Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing

Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

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

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

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

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

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

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

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

> LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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

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

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage.

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

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

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

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

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

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

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$Ramp\_Request_t = \frac{(UDStarget_{t-1} - AOutput_{t-1})}{(UDSLAtime_{t-1})}$$

$$RL\_Desired_t = AOutput_{t-1} + \left(Ramp\_Request_t * Case\_Eff\_time_{t-1}\right)$$

where:

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

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

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

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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

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

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

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants’ response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve

Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource’s output or the Demand Resource’s consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

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

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

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

where:

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

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

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

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

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

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance

Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

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

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

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

3.2.7 Billing.

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

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

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

(i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;

(ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;

(iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

(i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; 2013 for the EKPC Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each

historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Prior to the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights allocated at the aggregate load buses in a Zone. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section

7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Prior to the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights sink at the aggregate load buses in a Zone. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under

contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web

site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

SCHEDULE 12 -
PJM MEMBER LIST

A123 Systems, Inc.
AC Energy, LLC
AC Power Financial Corp.
Acciona Energy North America Corporation (AENAC)
A&C Management Group LLC
AEP Appalachian Transmission Company, Inc.
AEP Energy, Inc.
AEP Energy Partners, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP Retail Energy Partners, LLC
AEP West Virginia Transmission Company, Inc.
AES Armenia Mountain Wind, LLC
AES Beaver Valley LLC
AES Energy Storage, LLC
AES Laurel Mountain, LLC
Agway Energy Services, LLC
Air Liquide Industrial US, LP
Air Products & Chemicals, Inc.
AK Steel Corporation
Akula Energy, LLC
Alabama Power Company
Alcoa Power Marketing LLC
Algonquin Energy Services, Inc.
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, LLC
ALLETE, Inc. d/b/a Minnesota Power
Alliant Energy Corporate Services, Inc.
Alpha Gas and Electric, LLC
Ambit Northeast, LLC
Ameren Energy Marketing Company
American Efficient, Inc.
American Illuminating Company, LLC
American Municipal Power, Inc.
American Power Partners, LLC
American PowerNet Management, L.P.
American Transmission Company, LLC
American Transmission Systems Inc.
Amerigreeen Energy, Inc.
Anbaric Northeast Transmission Development Company, LLC
AP Gas & Electric (IL), LLC

AP Gas & Electric (MD), LLC
AP Gas & Electric (OH), LLC
AP Gas and Electric (NJ), LLC
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Appalachian Power Company
Apple Group LLC
APX Power Markets, Inc.
Aquenergy Systems Inc.
Aquila, Inc. d/b/a Aquila Networks
ArcelorMittal USA, LLC
ArcLight Energy Marketing, L.L.C.
Aspen Merchant Energy, LP
Associated Electric Cooperative, Inc.
Astral Energy LLC
Atlantic City Electric Company
Atlantic Grid Operations A, LLC
Automated Algorithms, LLC
Balance Power Systems, LLC
Baltimore Gas and Electric Company
Bank of America N.A.
Barclays Bank PLCBE Red Oak LLC
Barclays Capital Services, Inc
Bartram Lane, LLC
BBPC LLC d/b/a/ Great Eastern Energy
Beacon Power Corporation
Beech Ridge Energy LLC
Benton Foundry, Inc.
BG Energy Merchants, LLC
Big Rivers Electric Corporation
Big Sandy Peaker Plant, LLC
Big Savage, LLC
Big Sky Wind, LLC
Biogas Energy Solutions LLC
Bishop Hill Energy LLC
BJ Energy, LLC
Black Oak Capital, LLC
Black Oak Energy, LLC
Black River Commodity Energy Fund LLC
Black River Commodity Fund, Ltd.
Blackstone Wind Farm, LLC
Blackstone Wind Farm II, LLC
Blast Electric, LLC
Bluefin Electricity Trading, LLC
Bluegrass Generating Company, LLC
Blue Pilot Energy, LLC

Blue Ridge Power Agency, Inc.
BNP Paribas Energy Trading GP
Border Energy Electric Services, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Lavallette, New Jersey
Borough of Madison, New Jersey
Borough of Milltown
Borough of Mont Alto
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights
Borough of South River, New Jersey
Borough of Tarentum
Bounce Energy PA, LLC
BP Alternative Energy North America Inc.
BP Energy Company
Brighten Energy, LLC
Brookfield Energy Marketing Inc.
Brookfield Energy Marketing, LP
Brookfield Power Piney & Deep Creek LLC
Brookfield Renewable Energy Marketing US LLC
Bruce Power Inc.
Buckeye Power, Inc.
Buckeye Energy Brokers, Inc.
Calpine Bethlehem, LLC
Calpine Energy Services, L.P.
Calpine Mid Atlantic Marketing, LLC
Calvert Cliffs Nuclear Power Plant, Inc.
Cambria Cogen Company
Camp Grove Wind Farm, LLC
Canadian Wood Products – Montreal, Inc. dba CWP Energy
Cargill Power Markets, LLC
Carolina Power & Light Company
Castlebridge Energy Group, LLC
Cayler Trading Group, LLC
CBK Group, LTD
CCES LLC
Centaurus Energy Master Fund, LP
Central Transmission, LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy, LLC
Champion Energy Marketing LLC
Champion Energy Services, LLC

Chesapeake Transmission LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Cincinnati Bell Energy, LLC
Cinergy Retail Sales, LLC
Cinnamon Bay, LLC
Citigroup Energy Inc.
Citizen’s Electric Company of Lewisburg, PA
City of Batavia, Illinois
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Geneva (The)
City of Hamilton
City of New Martinsville – WV
City of Naperville
City of Philadelphia
City of Philippi – West VA
City of Rochelle
CleanLight Power + Energy, LLC
Clearview Electric, Inc.
Cleveland Electric Illuminating Company (The)
CMS Energy Resource Management Company
Coaltrain Energy LP
Cobalt Capital Partners, LLC
Cogentrix Virginia Leasing Corporation
Commercial Utility Consultants, Inc.
Commerce Energy Inc.
Commonwealth Chesapeake Company, LLC
Commonwealth Edison Company
Community Energy, Inc.
Comperio Energy LLC dba ClearChoice Energy
Con Edison Energy, Inc.
Conch Energy Trading, LLC
Conectiv Energy Supply, Inc.
ConocoPhillips Company
Consolidated Edison Company of New York, Inc.
Consolidated Edison Solutions, Inc.
Constellation Energy Commodities Group, Inc.
Constellation Energy Control and Dispatch, LLC
Constellation Energy Power Choice, Inc.
Constellation Energy Projects & Services Group, Inc.
Constellation NewEnergy, Inc.
Constellation Power Source Generation, Inc.
Consumers Energy Company
Coral Power, L.L.C.
Cordova Energy Company LLC
CornerStone Power Development, LLC

Corona Power LLC
Corporate Services Support Corp.
County of Frederick, VA
Covanta Delaware Valley, L.P.
Covanta Energy Group, Inc.
Covanta Essex Company
Covanta Union, Inc.
CP Energy Marketing (US) Inc.
CPV MARYLAND, LLC
CPV Shore, LLC
Credit Suisse Energy LLC
Credit Suisse (USA), Inc.
Crete Energy Venture, LLC
CrunchEnergy, LLC
Customized Energy Solutions, Ltd.
Cygnus Energy Futures, LLC
Darby Energy, LLLP
Dart Container Corporation of Pennsylvania
Dayton Power & Light Company (The)
DB Energy Trading LLC
DC Energy LLC
DC Energy Mid-Atlantic, LLC
DEL LIGHT INC.
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Demand Response Partners, Inc.
Demansys Energy, LLC
Denver Energy, LLC
Devonshire Energy, LLC
Diamond State Generation Partners, LLC
Direct Energy Business, LLC
Direct Energy Services, LLC
Discount Energy Group, LLC
Discount Energy, LLC
Discount Power, Inc.
Divine Power, Inc.
Division of the Public Advocate of State of Delaware
Dominion Energy Marketing, Inc.
Dominion Retail, Inc.
Domtar Paper Company, LLC
Downes Associates, Inc.
DPL Energy, LLC
DPL Energy Resources, LLC
DTE Energy Supply, Inc.
DTE Energy Trading, Inc.
Duke Energy Carolinas, LLC

Duke Energy Commercial Asset Management
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Shared Services, Inc.
Duquesne Conemaugh LLC
Duquesne Keystone LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Duquesne Power LLC
DynArb, LLC
Dynasty Power Inc.
Dynegy Energy Services, Inc.
Dynegy Marketing and Trade, LLC
Dynegy Power Marketing, Inc.
Dyon, LLC
E Minus LLC
E.ON Climate & Renewables North America Inc.
Eagle Energy, LLC
Eagle Point Power Generation LLC
East Coast Power Linden Holdings, L.L.C.
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
Ebensburg Power Company
eCap Network, LLC
EcoGrove Wind, LLC
EDF Industrial Power Services (IL), LLC
EDF Trading North America, LLC
Edison Mission Marketing & Trading, Inc.
Edison Mission Solutions, LLC
EDP Renewables North America, LLC
E.F. Kenilworth, Inc.
EFS Parlin Holdings, LLC
El Cap II, LLC
Elkem Metals Company-Alloy LP
El Paso Marketing, LLC
Elliot Bay Energy Trading, LLC
Elwood Energy LLC
EMC Development Company, Inc.
EME Homer City Generation, L.P.
Emera Energy Services, Inc.
Employers' Energy Alliance of Pennsylvania, Inc.
Emporia Hydropower Limited Partnership
ENBALA Power Networks, Inc.
Endure Energy, LLC
Energetix, Inc.
Energy America, LLC

Energy Algorithms LLC
Energy Analytics
Energy Analytics, Inc.
Energy Authority, Inc. (The)
EnergyConnect, Inc.
Energy Consulting Services, LLC
Energy Cooperative of America, Inc.
Energy Cooperative Association of Pennsylvania
Energy Curtailment Specialists, Inc. (ECS)
Energy Exchange Direct, LLC
Energy Exchange International, LLC
Energy International Power Marketing Corporation
Energy Investments, LLC
Energy-Links, LLC
Energy.me Midwest llc d/b/a energy.me
Energy Plus Holdings LLC
Energy Service Providers, Inc.
Energy Spectrum Inc.
EnergyUSA – TPC Corp.
EnerNOC, Inc.
EnerPenn USA, LLC
Enerwise Global Technologies, Inc.
Engage Energy America LLC
Enserco Energy, Inc.
Entegra Power Services LLC
EP Enterprises Incorporated
EP Ocean Peaking Power, LLC
EP Rock Spring, LLC
EPEX, Inc.
EPIC NJ/PA, L.P.
ERA MA, LLC
Essential Power, LLC
Ethical Electric Benefit Co.
Evergreen Community Power
Evraz Claymont Steel
Exel Power Sources, LLC
Exelon Business Services Company, LLC
Exelon Energy Company (The)
Exelon Generation Company, LLC
Exelon New England Power Marketing, Limited Partnership
Falcon Energy, LLC
FirstEnergy Solutions Corp.
First Point Power, LLC
Florida Power Corporation dba Progress Energy Florida, Inc.
Forest Investment Group, LLC
Fowler Ridge Wind Farm LLC

Fowler Ridge II Wind Farm LLC
FPL Energy Marcus Hook LP
Franklin Power LLC
Freepoint Commodities LLC
Fulcrum Energy Limited
Galt Power, Inc.
Gateway Energy Services Corporation
GDF SUEZ Energy Resources NA, Inc.
GDF Suez Retail Energy Solutions, LLC
Gelber Energy LLC
GenOn Energy Management, LLC
GenOn Potomac River, LLC
GenOn Power Midwest, LP
Georgia Power Company
Gerdau Ameristeel Energy, Inc
Glacial Energy of New Jersey, Inc.
Grand Ridge Energy LLC
Grand Ridge Energy II LLC
Grand Ridge Energy III LLC
Grand Ridge Energy IV LLC
Grand Ridge Energy V LLC
Granger Energy of Honey Brook, LLC
Grant Energy, Inc.
Grays Ferry Cogeneration Partnership
Great American Power, LLC
Great Bay Energy I, LLC
Great Bear Hydropower, Inc.
Green Mountain Energy Company
Greenpoint Trading Group, LLC
GRG ENERGY LLC
GSG 6, LLC
Gulf Power Company
G&G Energy, Inc.
Hagerstown Light Department
Handsome Lake Energy, LLC
Harrison REA, Inc. – Clarkesburg, WV
Hartz Group (The)
Hawks Nest Hydro LLC
Hazleton Generation LLC
Hemsworth Capital LP
Hess Corporation
Hess NEC, LLC
Hexis Energy Trading, LLC
Highland North LLC
Highlands Energy Group, LLC (The)
HIKO Energy, LLC

Hill Energy Resource & Services, LLC
Holcim (US), Inc.
Hoosier Energy REC, Inc.
HOP Energy, LLC
Horizon Power and Light, LLC
H-P Energy Resources, LLC
H.Q. Energy Services (U.S.), Inc.
HSBC Technology Services (USA), Inc.
Hudson Energy Services, LLC
Hudson Transmission Partners, LLC
Iberdrola Renewables, LLC
Icetec.com, Inc.
IDT Energy, Inc.
Illinois Citizens Utility Board
Illinois Municipal Electric Agency
Independence Energy Group, LLC
Independent Energy Consultants, Inc.
Indiana Michigan Power Company
Indiana Municipal Power Agency
Indiana Office of Utility Consumer Counselor (IN OUCC)
Industrial Energy Users-Ohio
Industrial Metal Treating Corp.
Ingenco Wholesale Power, LLC
Innoventive Power LLC
Integrys Energy Services, Inc.
IntelliGen Resources, LP
Intergrid Mideast Group LLC
International Paper Company
Interstate Gas Supply, Inc.
Interstate Power and Light Company
Invenergy LLC
Invenergy Nelson LLC
Invictus Capital Management, Ltd
IPR-GDF Suez Energy Marketing North America, Inc.
Iron Energy LLC
J. Aron & Company
J3 Energy Group (The)
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
JAS Energy, LLC
James River Cogeneration Company
Jersey-Atlantic Wind, LLC
Jersey Central Power & Light Company
Jersey Green Energy, LLC
JP Morgan Ventures Energy Corporation
JPTC, LLC
Juice Technologies, LLC

Kansas City Power & Light
KAP Analytics, LLC
Kasia C LLC
Katmai Energy, LLC
Keil & Sons, Inc dba Systrum Energy
Kentucky Municipal Power Agency
Kentucky Power Company
KeyTex Energy LLC
KeyTex Energy Solutions LLC
KFW Energy, LLC
Kimberly-Clark Corporation
Kimmel Energy Associates
Kingsport Power Company
Knedergy, LLC
KOREnergy, Ltd.
Krayn Wind LLC
Kuehne Chemical Company, Inc.
Kynetic Energy Solutions L&P Electric Inc., dba Leggett & Platt Electric Inc.
LCG Consulting
LDH Energy Funds Trading, Ltd.
Lee River Proprietary Strategies, Inc.
Legacy Energy Group, LLC (The)
Legends Energy Group, Inc.
Lehigh Capital, LLC
Lehigh Portland Cement Company
Lehman Brothers Commodity Services, Inc.
Letterkenny Industrial Development Authority – PA
Liberty Electric Power, LLC
Liberty Hill Power LLC
Liberty Power Corp., L.L.C.
Liberty Power Delaware, LLC
Liberty Power District of Columbia LLC
Liberty Power Holdings LLC
Liberty Power Maryland, LLC
Lilabell Energy LLC
Lincoln Generating Facility, LLC
Linde, Inc.
Linde Energy Services, Inc.
Linden VFT LLC
LM Power, LLC
Long Island Lighting Company d/b/a LIPA
Longview Power, LLC
Louis Dreyfus Energy Services L.P.
Louisville Gas and Electric Company/Kentucky Utilities Company
Lower Electric, LLC
Lower Mount Bethel Energy, LLC

LSP-Kendall Energy, LLC
LSP Safe Harbor Holdings, LLC
LSP University Park, LLC
Luminary Consulting LLC
Mac Trading, Inc.
Macquarie Energy, LLC
Madison Gas and Electric Co.
Madison Windpower LLC
MAG Energy Solution, Inc.
Magnolia Energy, LP
Major Energy Electric Services, LLCMaple Analytics, LLC
Marathon Power, LLC
Marina Energy, LLC
Maryland Office of People's Counsel
MC Squared Energy Services, LLC
MeadWestvaco Corporation
Meadow Lake Wind Farm, LLC
Meadow Lake Wind Farm II, LLC
Meadow Lake Wind Farm III, LLC
Meadow Lake Wind Farm IV, LLC
MEG Generating Company, LLC
Mehoopany Wind Energy LLC
Mercuria Energy America, Inc.
Merrill Lynch Commodities, Inc.
MET MA LLC
Metropolitan Edison Company
Metropolitan Energy, L.L.C.
Miami Valley Lighting, LLC
Michigan Public Power Agency
Microsoft Corporation
MidAmerican Energy Company
MidAtlantic Power Partners
Middlesex County Utilities Authorities
Midwest Energy Trading East LLC
Midwest Generation, LLC
Millennium Inorganic Chemicals, Inc.
Mint Energy, LLC
Mississippi Power Company
Monmouth Energy, Inc.
Monongahela Power Company d/b/a/ Allegheny Power
Monterey MA, LLC
Monterey MAF, LLC
Morgan Stanley Capital Group, Inc.
Morris Cogeneration, L.L.C Mt. Carmel Cogeneration Inc.
Morse Energy LLC
Mosaic Power, LLC

Moxie Liberty LLC
MP2 Energy NE, LLC
NASDAQ OMX Commodities Clearing, LLC
Natgasco, Inc.
National Railroad Passenger Corp. – AMTRAK
Nautilus Solar Energy, LLC
NedPower Mount Storm, LLC
Negawatt Business Solutions, Inc.
NEPM II, LLC
Neptune Regional Transmission System, LLC
NERC-Middlesex Solar I, LLC
New Covert Generating Company, LLC
New Jersey Division of the Ratepayer Advocate
New York State Electric & Gas Corporation
Newel Trading Group, LLC
NextEra Energy Power Marketing, LLC
NextEra Energy Services Illinois, LLC
NextEra Energy Services New Jersey, LLC
NJR Clean Energy Ventures Corporation
Noble American Gas & Power Corp.
Noble Americas Energy Solutions, LLC
Nordic Energy Services LLC
North America Power Partners LLC
North American Energy Credit and Clearing-Delivery LLC
North American Natural Resources – SBL, LLC
North American Power and Gas, LLC
Northampton Generating Company
Northeast Maryland Waste Disposal Authority
Northeast Transmission Development, LLC
Northeastern REMC
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northeast Utilities Service Company
Northern Illinois Municipal Power Agency
Northern States Power Company
Northern Virginia Electric Cooperative - NOVEC
NorthPoint Energy Solutions, Inc.
Northport USA, LLC
NorthWrite Energy Group, LLC
NRG Power Marketing, LLC
NuEnergen, LLC
NYSEG Solutions, Inc.
NYX Energy Corp.
Oasis Power, LLC dba Oasis Energy
Occidental Power Services, Inc.
Oceanside Power, LLC

Office of the People's Counsel for the District of Columbia
Ohio Consumer's Counsel
Ohio Edison Company
Ohio Power Company
Ohms Energy Company, LLC
Old Dominion Electric Cooperative
Olympus Power, LLC
Ontario Power Generation Inc.
Ontario Power Generation Energy Trading, Inc.
Ontelaunee Power Operating Company, LLC
Orion Asset Management, LLC
Owensboro Municipal Utilities
Ozark International, Inc.
P.H. Glatfelter Company
Pacific Summit Energy LLC
Palama, LLC
Palmco Power DC, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power OH, LLC
Palcom Power PA, LLC
Panda Power Corporation
Panther Creek Power Operating, LLC
Parma Energy LLC
PATH Allegheny Transmission Company, LLC
PATH West Virginia Transmission Company, LLC
Pattern Recognition Technologies, Inc.
Patton Wind Farm, LLC
Paulding Wind Farm II LLC
PBF Power Marketing, LLC
PECO Energy Company
Pedricktown Plant Holdings, LLC
PEI Power Corporation
PEI Power II, LLC
Penncat Corporation
Pennsylvania Electric Company
Pennsylvania Office of Consumer Advocate
Pennsylvania Power Company
Pennsylvania Renewable Resources, Associates
People's Power & Gas, LLC
Pepco Energy Services, Inc.
Perspective Energy USA LLC
PG Energy Services Inc. d/b/a/ PG Energy Power Plus
Phalanx Energy Services, LLC
Pioneer Prairie Wind Farm, LLC

Pirin Solutions, Inc.
PJS Capital, LLC
Planet Energy (Maryland) Corp.
Planet Energy (Pennsylvania) Corp.
Planet Energy (USA) Corp.
Plymouth Rock Energy, LLC
Potomac Edison Company (The) d/b/a/ Allegheny Power
Potomac Electric Power Company
Potomac Power Resources, Inc.
Powerex Corporation
PowerSecure, Inc.
PPL Brunner Island, LLC
PPL Electric Utilities Corporation dba PPL Utilities
PPL EnergyPlus, LLC
PPL EnergyPlus Retail, LLC
PPL Holtwood, LLC
PPL Ironwood, LLC
PPL Martins Creek, LLC
PPL Montour, LLC
PPL Susquehanna, LLC
Prairieland Energy, Inc.
Praxair, Inc.
Premcor Refining Group, Inc. (The)
Primary Power, LLC
Procter & Gamble Paper Products Company (The)
Property Endeavors LLC
Providence Heights Wind, LLC
PSEG Energy Resources & Trade LLC
Public Power & Utility of Maryland, LLC
Public Power & Utility of New Jersey, LLC
Public Power, LLC
Public Power, LLC [CT]
Public Service Electric and Gas Company
Pure Energy, Inc.
Quasar Energy Group, LLC
Quiet Light Trading, LLC
QVINTA, Incorporated
Raiden Commodities LP
Rainbow Energy Marketing Corporation
Rational Systems LLC
RBC Energy Services LP
RC Cape May Holdings, LLC
Realgy, LLC
Red Oak Power, LLC
Red Wolf Energy Trading, LLC
Reliable Power, LLCReliant Energy Electric Solutions, LLC

Reliant Energy Northeast, LLC
Reliant Energy Services, Inc.
Reliant Energy Solutions East, LLC
Renaissance Power, LLC
ResCom Energy, LLC
Reservoir Creek Energy, L.P.
Respond Power, LLC
RG Steel Sparrows Point, LLC
RI-Corp. Develement, Inc.
Richards' Energy Group (The)
Richland-Stryker Generation LLC
Riverside Generating Company, L.L.C.
RLTec US Inc.
Rochester Gas and Electric Corporation
Rockland Electric Company
Rolling Hills Generating, L.L.C.
Roth Rock Wind Farm, LLC
Royal Bank of Canada
RRI Energy Services, LLC
S.J. Energy Partners, Inc.
Safe Harbor Water Power Corporation
Safeway Inc.
Sailor's Star Co.
Santana Energy Services
Saracen Energy East LLC
Saracen Energy Power Trading LP
Saracen Power LLC
Schuylkill Energy Resources, Inc.
Scylla Energy LLC
Select Energy New York, Inc.
Sempra Generation
Servidyne Systems, LLC
SESCO ENTERPRISES LLC
Sheetz, Inc.
Siemens Energy, Inc.
SIG Energy, LLLP
Site Controls, Inc.
Smart Grid Solutions, LLC
SMART Papers Holdings, LLC
Smart Wire Grid, Inc.
Solios Power LLC
Solios Power Mid-Atlantic Trading, LLC
Solios Power Mid-Atlantic Virtual LLC
South Carolina Electric & Gas Company
Southeastern Chester County Refuse Authority
Southeastern Power Administration

Southern Indian Gas and Electric Company d/b/a Vectren Power Supply Inc.
Southern Power Company
Southern Maryland Electric Cooperative, Inc.
South Jersey Energy Company
South Jersey Energy Solutions, L.L.C.
Spark Energy, L.P.
Sperian Energy Corp
Starion Energy PA, Inc.
STATARB INVESTMENTS LLC
Stoney Creek Wind Farm, LLC
Strategic Transmission LLC
Stream Energy Columbia, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
STS Energy Partners LP
Sugar Creek Power Company, LLC
Summit Energy, LLC
SunCoke Energy, Inc
Sunoco, Inc. (R&M)
Sunoco Power Marketing, L.L.C.
Superior Plus Energy Services, Inc.
Sustainable Star LLC
Syncarpha Solar, LLC
Synergy Solutions Group LLC
Tangent Energy Solutions, Inc.
TAQA Gen X LLC
Target Corporation
TEC Trading, Inc.
Telemagine, Inc.
Tenaska Power Services Co.
Tenaska Virginia Parners, L.P.
Tennessee Valley Authority (The)
TERM Power & Gas, LLC
Texas Retail Energy, LLC
Thomas Jackson Management, Inc.
Thurmont Municipal Light Company
Tilton Energy, LLC
Titan Gas and Power
Toledo Edison Company (The)
Torofino Trading, LLC
Town of Berlin, Maryland
Town of Front Royal, Virginia
Town of Williamsport
Trademark Merchant Energy, LLC
Traditum Group LLC

Trans-Allegheny Interstate Line Company
TransAlta Energy Marketing (US) Inc.
TransCanada Power Marketing, Ltd.
Trans-Elect Development Company, LLC
TransMarket Group LLCUBS AG, acting through its London Branch
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trinity Powerworks, Inc.
TrueLight Commodities, LLC
Trumpet Trading Group, LLC
Trustees of the University of Pennsylvania, a Pennsylvania Non-Profit Corporation d/b/a University of Pennsylvania, The
Twin Cities Energy, LLC
Twin Cities Power, LLC
Twin Eagle Resource Management, LLC
UGI Development Company
UGI Energy Services, Inc.
UGI Utilities, Inc.
Union Electric Company d/b/a Ameren Missouri
Union Power Partners, L.P.
University Park Energy, LLC
U.S. Energy Partners dba PAETEC Energy
U.S. Energy Services, Inc.
UtiliTech, Inc.
Utility Advantage, LLC
Valero Power Marketing, LLC
VCharge, Inc.
Velocity American Energy Master I, LP
Vel Energy, LLC
Verde Energy USA, Inc.
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verisae, Inc.
Vette Energy, LLC
Vineland Municipal Electric Utility
Viridian Energy PA, LLC
Viridity Energy, Inc.
Virginia Division of Consumer Counsel
Virginia Electric and Power Company
Virginia State Corporation Commission
Vision Power, LLC
Vitol, Inc.
Vlast LLC
VMAC LLC
Wabash Valley Power Association, Inc.

Washington Gas Energy Services, Inc.
Webenergy.net, Inc. d/b/a Consumer Powerline
Wellsboro Electric Company
Wells Fargo Commodities, LLCWestar Energy, Inc.
West Deptford Energy, LLC
West Deptford Energy II, LLCWest Oaks Energy LP
West Penn Power Company d/b/a/ Allegheny Power
West Virginia Consumer Advocate Division
Western Reserve Energy Services, LLC
Wheelabrator Frackville Energy Co Inc.
Wheelabrator Portsmouth, Inc.
Wheeling Power Company
Wildcat Wind Farm I, LLC
Windy Bay Power LLC
Wisconsin Electric Power Company
Wisconsin Power and Light Company
Wisconsin Public Power, Inc.
Wolf Hills Energy, LLC
Wolverine Power Supply Cooperative, Inc.
Wolverine Trading, LLC
Woodway Energy Partners, LLC
WPS Westwood Generation, LLC
XO Energy CAL2 LP
XO Energy MA, LP
XO Energy MA2, LP
XO Energy NY2 LP
Xoom Energy, LLC
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
York Generation Company LLC
Your Energy Holdings, LLC
Zacho Energy Trading, LLC.
Zongyi Solar America Co. Ltd.

Section(s) of the
PJM Reliability Assurance Agreement

(Marked / Redline Format)

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:

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

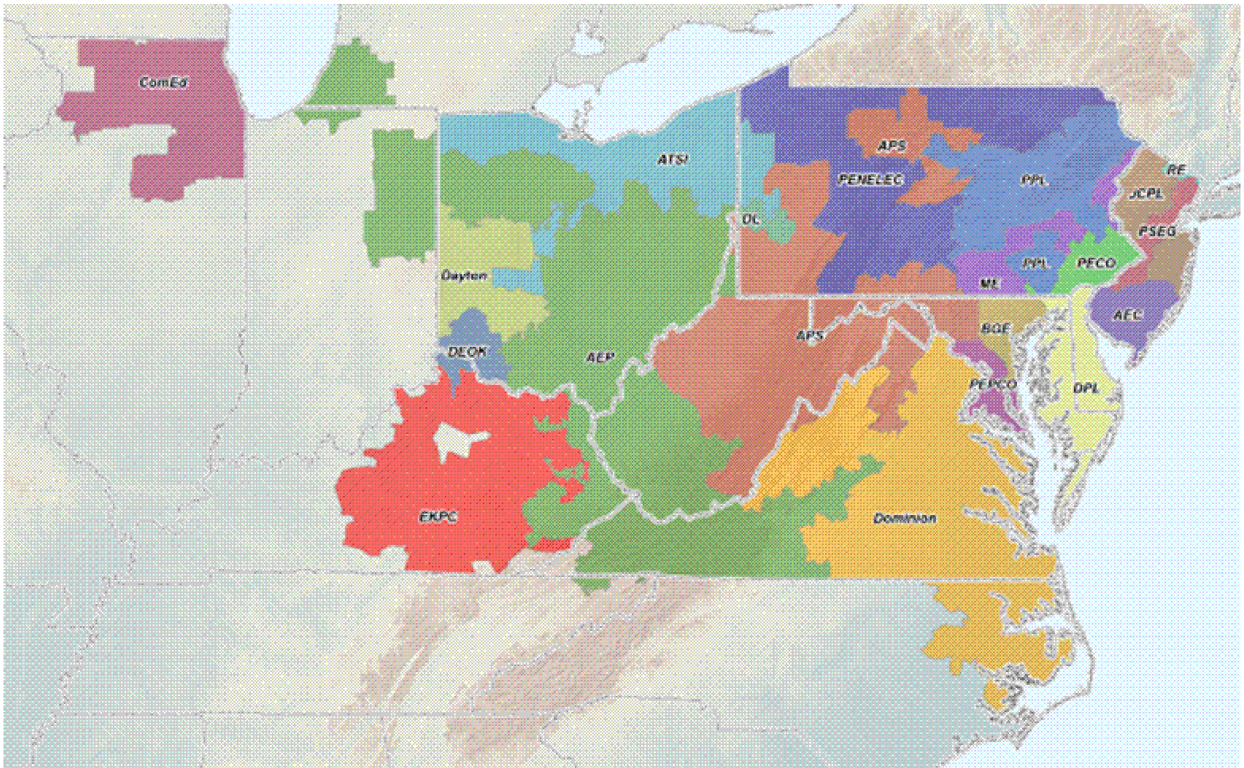
The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into

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.

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
East Kentucky Power Cooperative, Inc.	EKPC

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Energy, Inc.
AEP Retail Energy Partners LLC
Agway Energy Services, 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
- Indiana Michigan Power Company
- Kentucky Power Company
- Kingsport Power Company
- Ohio Power Company
- Wheeling Power Company.

American Illuminating Company, LLC
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
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.
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
Choice Energy, LLC dba 4 Choice 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.
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
Eagle Energy, LLC
East Kentucky Power Cooperative, Inc.
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.me Midwest llc d/b/a energy.me
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
Iron Energy LLC
J. Aron & Company
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jersey Central Power & Light Company
Keil and Sons, Inc. dba Systrum Energy
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
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.
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 DC, LLC
Palmco Power IL, LLC
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
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
Red Oak Power, 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
Titan Gas and Power
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
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, 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

Section(s) of the
PJM Consolidated Transmission Owners Agreement

(Marked / Redline Format)

ATTACHMENT A

TO THE CONSOLIDATED

TRANSMISSION OWNERS AGREEMENT

Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power

American Electric Power Service Corporation on behalf of its operating companies: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company

Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.

Dayton Power and Light Company

Virginia Electric and Power Company (Dominion Virginia Power)

Public Service Electric and Gas Company

PECO Energy Company

PPL Electric Utilities Corporation

Baltimore Gas and Electric Company

Jersey Central Power & Light Company

Metropolitan Edison Company

Pennsylvania Electric Company

Potomac Electric Power Company

Atlantic City Electric Company

Delmarva Power & Light Company

UGI Utilities, Inc.

Allegheny Electric Cooperative, Inc.

CED Rock Springs, LLC

Old Dominion Electric Cooperative

Rockland Electric Company

Duquesne Light Company

Neptune Regional Transmission System, LLC

Trans-Allegheny Interstate Line Company

Linden VFT, LLC

American Transmission Systems, Incorporated

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power

Duke Energy Ohio, Inc.

Duke Energy Kentucky, Inc.

City of Hamilton, OH

Hudson Transmission Partners, LLC

East Kentucky Power Cooperative, Inc.

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

PJM Interconnection, L.L.C.

By: ___________________________________
Name: Phillip G. Harris
Title: President and CEO
Date: December 15, 2005

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

Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power

By: ______________________________
Name: James R. Haney
Title: Vice President
Date: December 15, 2005

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

American Electric Power Service Corporation

By:_________________________________
Name:
Title:
Date: December 15, 2005

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

Exelon Corporation on behalf of its subsidiaries
Commonwealth Edison Company and Commonwealth Edison
Company of Indiana, Inc.

By:__________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

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

The Dayton Power and Light Company

By: ___________________________________
Name: Patricia K. Swanke
Title: Vice President - Operations
Date: December 15, 2005

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

Virginia Electric and Power Company (Dominion Virginia Power)

By:___________________________________
Name: Gary L. Sypolt
Title: President – Dominion Transmission
Date: December 15, 2005

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

Public Service Electric and Gas Company

By: ________________________________
Name: Ralph LaRossa
Title: Vice President - Electric Delivery
Date: December 15, 2005

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

Exelon Corporation on behalf of its subsidiary
PECO Energy Company

By:__________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

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

PPL Electric Utilities Corporation

By:___________________________________
Name: John F. Sipics
Title: President
Date: December 15, 2005

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

Baltimore Gas and Electric Company

By:______________________________
Name: Mark P. Huston
Title: Vice President, Electric Transmission and Distribution
Date: December 15, 2005

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

Jersey Central Power & Light Company

By: ________________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

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

Metropolitan Edison Company

By:________________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

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

Pennsylvania Electric Company

By:______________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

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

Potomac Electric Power Company

By:______________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

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

Atlantic City Electric Company

By: ________________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

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

Delmarva Power & Light Company

By:________________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

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

UGI Utilities, Inc.

By: ___________________________
Name: Richard E. Gill
Title: Assistant Secretary - Electric Transmission
Date: December 15, 2005

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

CED Rock Springs, LLC

By:__________________________________
Name:
Title:
Date: December 15, 2005

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

Old Dominion Electric Cooperative

By:_______________________________
Name:
Title:
Date: December 15, 2005

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

Rockland Electric Company

By:________________________________
Name:
Title:
Date: December 15, 2005

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

Duquesne Light Company

By:__________________________________
Name:
Title:
Date: December 15, 2005

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

Allegheny Electric Cooperative, Inc.

By: ________________________________
Name: Richard W. Osborne
Title: Vice President Power Supply & Engineering
Date: December 15, 2005

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

Neptune Regional Transmission System, LLC

By: ___________________________________
Name: Edward M. Stern
Title: CEO
Date: March 7, 2007

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

Trans-Allegheny Interstate Line Company

By: ___________________________________
Name: James R. Haney
Title: Vice President
Date: November 8, 2007

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

Linden VFT, LLC

By: ___________________________________
Name: Andrew J. Keleman
Title: Authorized Representative
Date: April 1, 2009

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

American Transmission Systems, Incorporated

By: ________________________________
Name: Richard R. Grigg
Title: President
Date: December 17, 2009

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

City of Cleveland, Department of Public Utilities
Division of Cleveland Public Power

By: _ ________________________________
Name: Barry A. Withers
Title: Director
Date: March 22, 2011

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

Duke Energy Ohio, Inc.

By: _ ________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

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

Duke Energy Kentucky, Inc.

By: _ ________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

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

City of Hamilton, OH

By: ______________________________
Name: Joshua A. Smith
Title: City Manager
Date: February 29, 2012

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

Hudson Transmission Partners, L.L.C.

By: ________________________________
Name: Jeffrey T. Wood
Title: Senior Vice President
Date: February 8, 2013

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

East Kentucky Power Cooperative, Inc.

By: ______________________________
Name: Anthony S. Campbell
Title: President & CEO
Date: March 26, 2013

Attachment B

Revisions to the
PJM Open Access Transmission Tariff,
PJM Operating Agreement,
PJM Reliability Assurance Agreement,
PJM Consolidated Transmission Owners Agreement
and
PJM Service Agreements

(Identified by Additional Cover Pages)

(Clean Format)

Section(s) of the PJM Open Access Transmission Tariff

(Clean Format)

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

Zone	Rate ($/MWh)
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	0.0796
Metropolitan Edison Company	0.0796
Pennsylvania Electric Company	0.0796
Rockland Electric Company	0.2475
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company[1]	0.0797
Duquesne Light Company	0.0520
American Transmission Systems, Incorporated ("ATSI")	Rate updated annually Per Attachment H-21
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	Rate updated annually Per Attachment H-22
East Kentucky Power Cooperative, Inc. ("EKPC")	Per Attachment H-24

[1] Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$.0912//MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	1.41
Baltimore Gas and Electric Company	2.28
Delmarva Power & Light Company	2.17
PECO Energy Company	7.57
PP&L, Inc. Group	3.88
Potomac Electric Power Company	0.92
Public Service Electric and Gas Company	7.55
Jersey Central Power & Light Company	3.71
Metropolitan Edison Company	1.22
Pennsylvania Electric Company	1.90
Rockland Electric Company	0.57
Commonwealth Edison Company	41.42
AEP East Operating Companies	14.56
The Dayton Power and Light Company	2.41
Duquesne Light Company	1.20
American Transmission Systems, Incorporated ("ATSI")	3.05
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	4.17[2]
East Kentucky Power Cooperative, Inc. ("EKPC")	0.0

[2] Any change to this share must be made as a tariff filing under Section 205 of the Federal Power Act.

SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	32.114	2.676	0.6176	0.1235	0.0882
ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone[5/]	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone[6/]					
ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse PJMSettlement for any amounts payable as sales, excise, "Btu," carbon, value-added or similar

taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of $3.60/kw/year, $0.30/kw/mo., $0.0692/kw/week, $0.0099/kw/day-off-peak, or $0.0138/kw/day-on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 8
Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	**Monthly Charge ($/kW)**	**Weekly Charge ($/kW)**	**Daily On-Peak[1/] Charge ($/kW)**	**Daily Off-Peak[2/] Charge ($/kW)**	**Hourly On-Peak[3/] Charge ($/MWh)**	**Hourly Off-Peak[4/] Charge ($/MWh)**
Border of PJM	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE Zone	1.984	0.4580	0.0920	0.0650	5.7	2.72
BG&E Zone	1.306	0.3010	0.0600	0.0430	3.8	1.80
Delmarva Zone	1.615	0.3730	0.0750	0.0530	4.6	2.21
JCPL Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
MetEd Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
Penelec Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
PECO Zone	2.189	0.5051	0.1010	0.0722	6.3	3.01
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *	PPL: * AEC: 0.11 UGI: *	PPL: * AEC: 0.05 UGI: *
Pepco Zone	1.750	0.4040	0.0810	0.0580	5.0	2.40
PSE&G Zone	1.975	0.4557	0.0911	0.0651	5.7	2.71
AP Zone	1.737	0.4009	0.0802	0.0573	5.0	2.39
Rockland Zone	2.676	0.6176	0.1235	0.0882	7.7	3.67
ComEd Zone[5/]	[6/]					

* PPL Electric Utilities Corporation’s and UGI Utilities’ respective component of the total charge is posted on the PJM Internet website.

AEP East Zone[7/] Nov. 1, 2005 SECA Ended W-JF Line In	AEP East Zone[7/]	Rate Pursuant to Attachment H-14	Monthly Charge X 12 / 52 ~~0.249 48~~	Weekly Charge / 5	Weekly Charge / 7	Daily On-Peak Charge / 16
Dayton Zone	Dayton Zone	1.306	0.3014	0.060 3	0.0431	3.77
Duquesne Zone	Duquesne Zone	1.18	0.27	0.054 0	0.0386	3.38
Dominion Zone[8/]	Dominion Zone[8/]					
ATSI Zone	ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

1/ Monday - Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ 7:00 a.m. up to the hour ending 11:00 p.m.

4/ 11:00 p.m. up to the hour ending 7:00 a.m.

5/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 9 below to determine the actual charge to the Transmission Customer.

6/ The charges for the ComEd zone are posted on PJM's website. In addition to the other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:
Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;
Monthly Rate - $/kW/month. = Annual Rate divided by 12;
Weekly Rate - $/kW/week = Annual Rate divided by 52;
Daily rate - $/kW/day = Weekly Rate divided by 5.
In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be

needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

7/ The rates for non-firm point-to-point transmission service in the AEP Zone will be charged at the monthly, weekly, daily or hourly rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount, ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 8 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

8/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Monthly Charge - $/kW/month = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 12 divided by 1000 kW/MW;

Weekly Charge - $/kW/week = 12 times Monthly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7;

Hourly On-Peak Charge - $/MWh = Daily On-Peak Charge / 16 hours *1000 kW/ MW;

Hourly Off-Peak Charge - $/ MWh = Daily Off-Peak Charge / 24 hours *1000 kW/ MW.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery or Daily Off-Peak Delivery, shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an Affiliate’s use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion, Losses and Capacity Export:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion charges. If the Transmission Customer so elects, it shall either (a) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is positive, pay the higher of the applicable Transmission Congestion Charge or the applicable rate under section (1) above, or (b) if the

applicable Transmission Congestion Charge as calculated pursuant to Attachment K is negative, pay or be credited the sum of the applicable Transmission Congestion Charge and the rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay for any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

7) **Transmission Enhancement Charges:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd’s share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment (“SECA”) revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer’s bill in that month for service under this schedule.

9) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 10-NERC
North American Electric Reliability Corporation Charge

a) The North American Electric Reliability Corporation (NERC) is the Electric Reliability Organization (ERO) certified by the Federal Energy Regulatory Commission. Its purpose is to ensure the reliability of the interconnected bulk power system. This schedule will recover a share of NERC's costs of operations as set forth below.

b) PJM will charge each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the NERC Rate times the total quantity in MWhs of energy delivered to the load (including losses) that such customer serves in the PJM Region, excluding the Dominion Zone, the ATSI Zone and the EKPC Zone during such month. The exclusion applicable to the ATSI Zone shall expire on January 1, 2012.

c) A fixed rate will be charged for the first eleven billing periods of the current year. During the final billing period, a true-up component will be applied to adjust for any under or over collections for the current year.

d) NERC will submit final estimated costs to be recovered under this Schedule 10-NERC, determinants, and rates to the Transmission Provider no later than September 30th for the next calendar year. The Transmission Provider will post the rates for both components for the next calendar year no later than October 31st of the current year.

e) The NERCR shall be calculated each year in accordance with the formula:

$$NERCR = \frac{CYNC}{PJMNTHL}$$

where:

NERCR is the NERC Rate.

CYNC is the Current Year NERC Charges. These charges are the FERC approved funding for NERC for the year for which NERCR is being calculated. In the final billing for each calendar year a true-up component will be included applying any credit or deficiencies for the current year based on NERC's actual revenues as compared to NERC's FERC approved funding received under the schedule for the current year.

The Transmission Provider's NERC Total Hourly Load (PJMNTHL) is the estimated total quantity in MWhs of energy to be delivered to load (including losses) in the PJM Region, less the total quantity in MWhs of energy to be delivered to load (including losses) in the Dominion Zone, under Network Integration and Point-to-Point Transmission Service by all customers during the year for which NERCR is being calculated.

f) NERC is responsible for pursuing any and all defaults under this Schedule 10-NERC. Thus, the Transmission Provider will not deem any customer in default under the tariff for failure to pay any charges under this Schedule 10-NERC.

SCHEDULE 10-RFC
Reliability First Corporation Charge

a) Reliability*First* Corporation (RFC) is one of the Regional Entities of NERC. Its purpose is to ensure the reliability of the interconnected bulk power system. This schedule will recover RFC's statutory costs of operations as set forth below.

b) PJM will charge each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the RFC Rate times the total quantity in MWhs of energy delivered to load (including losses) that such customer serves in the PJM Region, excluding the Dominion Zone, the ATSI Zone and the EKPC Zone, during such month. The exclusion applicable to the ATSI Zone shall expire on January 1, 2012.

c) A fixed rate will be charged for the first eleven billing periods of the current year. During the final billing period, a true-up component will be applied to adjust for any under or over collections for the current year.

d) NERC will submit final estimated costs to be recovered under this Schedule 10-RFC, determinants, and rates to the Transmission Provider no later than September 30th for the next calendar year. The Transmission Provider will post the rates for both components for the next calendar year no later than October 31st of the current year.

e) The RFCR shall be calculated each year in accordance with the formula:

$$\text{RFCR} = \frac{\text{CYRC}}{\text{PJMRTHL}}$$

where:

RFCR is the RFC Rate.

CYRC is the Current Year RFC Charges. These charges are the FERC approved funding for RFC for the year for which RFCR is being calculated. In the final billing for each calendar year a true-up component will be included applying any credit or deficiencies for the current year based on RFC's actual revenues as compared to RFC's FERC approved funding received under the schedule for the current year.

The Transmission Provider's RFC Total Hourly Load (PJMRTHL) is the estimated total quantity in MWhs of energy to be delivered to load (including losses) in the PJM Region, less the total quantity in MWhs of energy to be delivered to load (including losses) in the Dominion Zone, under Network Integration and Point-to-Point Transmission Service by all customers during the year for which RFCR is being calculated.

f) RFC is responsible for pursuing any and all defaults under this Schedule 10-RFC. Thus, the Transmission Provider will not deem any customer in default under the tariff for failure to pay any charges under this Schedule 10-RFC.

ATTACHMENT C-3

Conversion of Service in the EKPC Zone

The Office of the Interconnection is scheduled to become the Transmission provider for the EKPC Zone under the terms of this Tariff on June 1, 2013 and the EKPC tariff shall be superseded with respect to the EKPC Zone. Reservations purchased on the EKPC OASIS nodes prior to the integration of the EKPC Zone which remain in place following the integration date shall be converted to the appropriate service under this Tariff and subject to the rates, terms and conditions of this Tariff. In addition, interconnection requests under the EKPC tariff pending prior to the integration of the EKPC Zone shall be converted to requests for interconnection under this Tariff. This Attachment sets forth the principles that shall govern such conversions of service.

Customers who have reservations that need to be converted will be contacted directly by the Office of the Interconnection. Not all transmission service provided under the EKPC tariff exactly matches a service under this Tariff. Differences include variations in product definitions and PJM Region LMP pricing points. These variances in transmission requests will be converted into the defined product types explained below. The guidelines for the conversion of service are as follows:

1. All existing reservations will retain the same capacity (in megawatts) and will be converted to a comparable PJM product and duration with the applicable point of receipt, point of delivery and path. Firm Point-to-Point Transmission Service redirected on a non-firm basis to Secondary Receipt or Delivery Points under the EKPC tariff prior to the EKPC integration date will be converted to service under this Tariff on the basis of the original firm points of receipt and delivery. Firm Point-to-Point Transmission Service redirected on a firm basis under section 22.2 (Modification on a Firm Basis) (or equivalent) of the EKPC tariff prior to the EKPC integration date will be converted to service under this Tariff on the basis of the modified firm points of receipt and delivery.

2. All EKPC reservations extending past the integration date must select Source and Sink LMP pricing points corresponding to the appropriate interface, where applicable, willing to pay through (or not), a new product if applicable. Willing to pay congestion (or not) must be determined no later than 12:00 noon EPT, 30 days prior to the EKPC integration start date. In the event the customer does not choose within the allotted deadline above, PJM will convert the service to the most closely analogous service under the PJM Tariff, in PJM's judgment. Willing to pay congestion is optional for non-firm and non-designated transmission service; Firm service, by definition, is willing to pay congestion. All converted service (as they exist) will be placed on the PJM OASIS no later than 30 days prior to the EKPC integration start date.

3. All EKPC import reservations will be converted to one of the following service types as defined by this Tariff or on the PJM OASIS. Spot market, Non-Firm Point-to-Point, Network Designated or Network Non-Designated. This choice will be made on an individual reservation basis, based on the scheduling intent of the reservation.

4. All existing EKPC Zone extended transmission requests (*i.e*. monthly, weekly, daily) that span multiple months will be converted to their largest individual components as defined on the PJM OASIS. For example, a monthly request from October 1 to December 1 will be converted to two individual monthly requests, October 1 to November 1, and November 1 to December 1; and daily request from January 1 of one year to January 1 of the next year will be converted to yearly service.

5. Sliding monthly service (*i.e*., monthly service that does not run from the first day of the given month to the last day of the given month) will be converted to weekly and daily service.

6. Sliding weekly service (*i.e*., weekly service that does not run from Monday at 00:00 to Sunday at 23:59) will be converted to daily service.

7. Transmission service that is not currently confirmed on the EKPC OASIS nodes and is in active status such as “Received,” “Queued” or “Study” will be transferred to the integrated PJM OASIS node and will maintain its initial queued date.

8. All “Grandfathered” requests that exist on the EKPC OASIS nodes will require a reservation on the PJM OASIS node.

9. To facilitate the OASIS transition, from one month prior to the respective integration start date until such integration start date, requests for service that are active on or after such date one month prior to the integration start date should be made on both the pre-integration transmission owner or OASIS nodes and the PJM OASIS nodes.

10. Reservations will be converted based on the priority of the product.

11. Although the Office of the Interconnection will attempt to convert existing transmission reservations into comparable reservations on the PJM OASIS, there will be unique instances where this will not be possible (*e.g*., reliability issues, etc.). In this case, reservations will be reviewed on a case-by-case basis. Transmission service that is not currently accepted on the EKPC Zone OASIS nodes and is in active state such as “Received,” “Queued” or “Study” will be assigned the same status and queue position on the PJM OASIS as it had on the EKPC OASIS prior to conversion.

12 Converted Point-to-Point and Network transmission service reservations that extend beyond or begin after the integration commencement date will be posted to the PJM

OASIS web page on an as-needed basis. The web page will identify the original EKPC Zone reservation and the new PJM OASIS reservation.

13. An Interconnection Request pending under the EKPC tariff at the time of the integration of the EKPC Zone shall be assigned the same priority date under this Tariff as such request had under the EKPC tariff immediately prior to such integration. The Interconnection Request will be assigned a PJM queue identifier such that the Interconnection Customer's priority date relative to existing PJM queued Interconnection Requests can be easily determined. All such Interconnection Requests will be integrated into PJM's existing Interconnection Queue(s), effective on the EKPC integration start date, and will be subject to the generation interconnection procedures under Parts IV and VI of this Tariff. On the EKPC integration date, PJM will assume the technical studies that have been started under the EKPC tariff. After the studies are complete, the Interconnection Customer will be required to pay for any Network Upgrades and/or Local Upgrades that are needed for the generating unit to qualify for Capacity Interconnection Rights under this Tariff.

ATTACHMENT H-24
Annual Transmission Rates – EKPC
for Network Integration Transmission Service
and Point-to-Point Transmission Service

1. The Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service and Point-to-Point Transmission Service are the product of the formula shown in Attachment H-24A, and will be posted on the PJM website. The ATRR and the rates reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of East Kentucky Power Cooperative, Inc. ("EKPC").

2. The formula rate in this attachment shall be effective until amended by EKPC or modified by the Commission.

3. EKPC and American Electric Power shall be subject to the additional provisions of PJM Service Agreement No. 1530, Composite Interconnection Agreement between American Electric Power Service Corporation and East Kentucky Power Cooperative.

4. EKPC and Louisville Gas & Electric Company/Kentucky Utilities Company shall be subject to the additional provisions of PJM Service Agreement No. 3518, Service Agreement For Network Integration Transmission Service among PJM Interconnection, L.L.C., PJM Settlement Inc. and Louisville Gas and Electric Company/Kentucky Utilities Company.

Formula Rate - Non-Levelized | For the 12 months ended 12/31/20__

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 0
	REVENUE CREDITS	Note A	Total	Allocator		
2	Account No. 454	(page 4, line 34)	$ 0	TP	0.00000	$ 0
3	Account No. 456.1 (Net of Revenues from Grandfathered Transactions)	(page 4, line 35)	0	TP	0.00000	138,871
4	Revenues from Grandfathered Transactions	Note B	0	TP	0.00000	155,395
5	Revenues from service provided by the ISO at a discount		0	TP	0.00000	0
5a	Transmission Enhancement Credit		0	TP	0.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5b)					$ 0
6a	True-up Adjustment	Note C				$ -
7	NET REVENUE REQUIREMENT	(line 1 minus line 6 plus line 6a)				$ 0
	DIVISOR					
8	1 CP	Note D				0
9	12 CP	Note E				0
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$ 0.000			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$0.000			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.000			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$0.000			
			On-Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.000			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.000	Capped at weekly rate		$0.000
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.000	Capped at weekly and daily rate		$0.000

Formula Rate - Non-Levelized

For the 12 months ended 12/31/20__

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.	(1) RATE BASE	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	204.46.g	$ 0	NA		
2	Transmission	206.58.g	0	TP	0.00000	$ 0
3	Distribution	206.75.g	0	NA		
4	General & Intangible	204.5.g & 206.90.g	0	W/S	0.00000	0
5	Common		0	CE	0.00000	0
6	TOTAL GROSS PLANT(sum lines1-5)		$ 0	GP=	0.000%	$ 0
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 0	NA		
8	Transmission	219.25.c	0	TP	0.00000	$ 0
9	Distribution	219.26.c	0	NA		
10	General & Intangible	219.28.c	0	W/S	0.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 0			$ 0
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 0			
14	Transmission	(line 2 - line 8)	0			$ 0
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	0			0
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		$ 0	NP=	0.000%	$ 0
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	272.Total 281.k	$ -	NA	zero	$ -
20	Account No. 282 (enter negative)	274.Total 282.k	0	NP	0.00000	0
21	Account No. 283 (enter negative)	276.Total 283.k	0	NP	0.00000	0
22	Account No. 190	234.Total 190.c	0	NP	0.00000	0
23	Account No. 255 (enter negative)	266.Total.h	0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19-23)		$ 0			$ 0
25	LAND HELD FOR FUTURE USE	214.Total.d, Note F	$ -		0.00000	$ -
	WORKING CAPITAL					
26	CWC	calculated, Note G	$ 0			0
27	Materials & Supplies	227.8.c	0	TE	0.00000	0
28	Prepayments (Account 165)	110.46.c, Note G	0	GP	0.00000	0
29	TOTAL WORKING CAPITAL (sum lines 26-28)		$ 0			$ 0
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 0			$ 0

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	
	O&M							
1	Transmission	321.100	$	0	TE	0.00000	$	0
2	Less Account 565	321.Acct 565		0	TE	0.00000		0
3	A&G	321.168		0	W/S	0.00000		0
4	Less FERC Annual Fees	N/A		0	W/S	0.00000		0
5	Less Non-safety Advertising	Note H		0	W/S	0.00000		0
5a	Less KPSC Regulatory Expenses	Note H		0				0
5b	Plus Transmission Related Regulatory Exp	Note H		0	TE	0.00000		0
5c	Plus Prorated PJM Transition Expense	Note H		0				0
6	Common			0	CE	0.00000		0
7	Transmission Lease Payments			0		0.00000		0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6,7 less lines 1a, 2, 4, 5)		$	0			$	0
	DEPRECIATION EXPENSE							
9	Transmission	336.7.f	$	0	TP	0.00000	$	0
10	General and Intangible	336.9.f		0	W/S	0.00000		0
11	Common	336.10.f		0	CE	0.00000		0
12	TOTAL DEPRECIATION (Sum lines 9-11)		$	0			$	0
	TAXES OTHER THAN INCOME TAXES							
	LABOR RELATED							
13	Payroll	Note I	$	0	W/S	0.00000	$	0
14	Highway and vehicle	Note I		0	W/S	0.00000		0
15	PLANT RELATED							
16	Property	Note I		0	GP	0.00000		0
17	Gross Receipts			0	NA	NA		0
18	Other			0	GP	0.00000		0
19	Payments in lieu of taxes			0	GP	0.00000		0
20	TOTAL OTHER TAXES (sum lines 13-19)		$	0			$	0
	INCOME TAXES	Note J						
21	T=1 - {[(1-SIT) * (1-FIT)] / (1 - SIT * FIT * p)} =			0.000000%				
22	CIT=(T/1-T) * (1-(WCLTD/R)) =			0.000000%				
23	1 / (1 - T) = (from line 21)			0.0000				
24	Amortized Investment Tax Credit	266.8.f (enter negative)		0				
25	Income Tax Calculation (line 22 * line 28)		$	0	NA		$	0
26	ITC adjustment (line 23 * line 24)			0	NP	0.00000		0
27	Total Income Taxes	(line 25 plus line 26)	$	0			$	0
28	RETURN							
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 29)]		$	0	NA		$	0
29	REVENUE REQUIREMENT (sum lines 8,12, 20, 27, 28)		$	0			$	0

Formula Rate - Non-Levelized | For the 12 months ended 12/31/20__

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.							
	TRANSMISSION PLANT INCLUDED IN ISO RATES						
1	Total transmission plant (page 2, line 2, column 3)						0
2	Less transmission plant excluded from ISO rates						0
3	Less transmission plant included in OATT Ancillary Services	See Supporting Exhibit, Page 5 of 8, Line 4, (Note K)					0
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)						0
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	0.00000
	TRANSMISSION EXPENSES						
6	Total transmission expenses (page 3, line 1, column 3)						0
7	Less transmission expenses included in OATT Ancillary Services	Note L					0
8	Included transmission expenses (line 6 less line 7)						0
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.00000
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.00000
	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP	Allocation		
12	Production	354.18.b	0	0.00	0		
13	Transmission	354.19.b	0	0.00	0		
14	Distribution	354.20.b	0	0.00	0		W&S Allocator
15	Other	354.21,22,23,24.b	0	0.00	0		($ / Allocation)
16	Total (sum lines 12-15)		0		0	=	0.00000
	COMMON PLANT ALLOCATOR (CE)		%		% Electric		W&S Allocator
17	Electric	200.3.c	0.00		(line 17 / line 20)		(line 16)
18	Gas	201.3.d	0.00		0.00000	*	0.00000
19	Water	201.3.e	0.00				
20	Total (sum lines 17 - 19)		0.00				
	RETURN (R)						$
21		Long Term Interest (117, sum of 58.c through 65.c)					0
22		Preferred Dividends (118.29c) (positive number)					0
	Development of Cost of Capital:						
23	Long Term Debt	(112.23c) See Supporting Exhibit, Page 7 of 8				$	0
24	Proprietary Capital	(112.15.c)					0
25	Less Account 216.1	(112.12.c) (enter negative)					0
26		Total Capital	(sum lines 23-25)			$	0
			$	%	Cost		Weighted
27	Long Term Debt (112.23c)	Note M	0	0.00%	0.000%		0.000%
28	Proprietary Capital (112.15.c)	Note N	0	0.00%	**0.000%**		0.000%
29	Total (sum lines 27-28)		0		**R =**		**0.000%**
30	Effective TIER	Note O			**TIER =**		**0.00**
	REVENUE CREDITS						
	ACCOUNT 447 (BUNDLED SALES FOR RESALE)		(310-311)				
31	a. Bundled Non-RQ Sales for Resale (311.x.k)					$	0
32	b. Bundled Sales for Resale included in Divisor on page 1						0
33	Total of (a)-(b)					$	0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	See Supporting Exhibit, Page 6 of 8, Line 3 (Note P)				$	0
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)	See Supporting Exhibit, Page 6 of 8, Line 17 (Note Q)				$	0

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

General Note: **References to pages in this formulary rate are indicated as: (page#, line#, col.#)**
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Formulary Rate Template.
B	Revenue from AEP Grandfathered Agreement. See Rev Cred Support, Attachment H-24A, Supporting Exhibit, page 6 of 8, line 16
C	Calculated in accordance with the EKPC Formulary Rate Protocols in Attachment H-24B of this Tariff. See Appendix C
D	EKPC 1 CP is EKPC's highest Monthly Firm Transmission System Peak Load based on the source data as described in Note 1 of Attachment H-24A, Page 8 of 8, plus transmission service provided for others over the EKPC transmission system, plus wheel-out to EKPC load connected to AEP/KP, Duke Ky, and LGE/KU See Attachment H-24A, Supporting Exhibit, Page 8 of 8
E	EKPC 12 CP is EKPC's Monthly Firm Transmission System Peak Load based on the source data as described in Note 1 of Attachment H-24A, Page 8 of 8, plus transmission service provided for others over the EKPC transmission system, plus wheel-out to EKPC load connected to AEP/KP, Duke Ky, and LGE/KU See Attachment H-24A, Supporting Exhibit, Page 8 of 8
F	Identified in EKPC Form FF1 as being non-transmission related. See Attachment H-24A, Supporting Exhibit, Pg 2 of 8
G	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3 of 5, line 8, column 5. Prepayments are the electric-related prepayments booked to Account No. 165 and reported on EKPC Form FF1, Ref Pg 110, line 46.
H	Line 5 - Remove non-safety related advertising included in Account 930.1. See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 3 Line 5a - Remove Total Regulatory Commission Expenses - See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 4 Line 5b - Add Back Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting - See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 6 Line 5c - Add EKPC costs relating to PJM transition. See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 14
I	In accordance with RUS accounting standards, EKPC allocates all payroll and property taxes to the functional account. Labor- and plant-related taxes are already included in the appropriate transmission account.
J	As a member-owned non-profit RUS generation and transmission cooperative, EKPC is exempt from state and from federal income taxes under 501(c)(12) of Internal Revenue Code
K	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, included in Account 561. See Attachment H-24A, Supporting Exhibit, Page 4 of 8.
M	Debt cost rate = long-term interest (line 21) / long term debt (line 27).
N	Proprietary Capital Cost calculated to achieve TIER of 1.50
O	TIER value approved by KPSC in Case No. 2010-000167
P	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
Q	Net of retained legacy transactions. See Attachment H-24A, Supporting Exhibit, page 6 of 8.

East Kentucky Power Cooperative, Inc.
Transmission Formula Rate Revenue Requirement
Utilizing EKPC 20__ Form FF1 Data
For Rates Effective June 1, 20__

Schedule 1A Rate Calculation

	Line No.		Source	Revenue Requirement		
A.	Schedule 1A Annual Revenue Requirements					
	1	Total Load Dispatch & Scheduling (Account 561)	Supporting Exh, page 4 of 8, line 11	$	0	
		Less allocated amount for steam production [(Line 6c/Line 6b) * Line 1]		$	0	
		Total Load Dispatch & Scheduling (Account 561) excluding Steam		$	0	
	2	Revenue Credits for Schedule 1A	Note 1	$	-	
	3	Net Schedule 1A Revenue Requirement for Zone		$	0	
	4	Less: True Up Under/(Over) Recovery for 12 months ended 12/31/20__	Note 2	$	-	
	5	Schedule 1A Recovery Amount for 12 Months ended		$	0	
B.	Schedule 1A Rate Calculations		Note 3			
	6	2012 Requirements Sales for Resale	Note 4		0	MWh
	6a	Plus Non-requirements Sales for Resale	Note 5		0	
	6b	Subtotal	Note 6		0	
	6c	Less Equivalent Steam			0	
	6d	Net MWh			0	MWh
	7	Schedule 1A rate $/MWh (Line 5 / Line 6)	(Line 3 / Line 6)		$0.0000	$/MWh

Notes:

(1) Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of EKPC's zone during the year used to calculate rates under Attachment H-24A
(2) Amount from Attachment H-24A, Appendix C, line 13 for stated year.
(3) Sourced from EKPC Form FF1, Ref Pg 401, adjusted for equivalent steam sold
(4) FF1, Ref Page 401, Line 23
(5) FF1, Ref Page 401, Line 24
(6) FF1, Ref Page 401, Footnote

Rate Formula Template
Utilizing Attachment H-24A
East Kentucky Power Cooperative, Inc.
RTEP - Transmission Enhancement Charges
To be completed in conjunction with Attachment H-24A

	(1)	(2)	(3)	(4)
Line No.		Attachment H-24A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Attachment H-24A, p 2, line 2 col 5 (Note A)	0	
2	Net Transmission Plant - Total	Attachment H-24A, p 2, line 14 col 5 (Note B)	0	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attachment H-24A, p 3, line 8 col 5	0	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.00%	0.00%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attachment H-24A, p 3, lines 10 & 11, col 5 (Note H)	0	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.00%	0.00%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attachment H-24A, p 3, line 20 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.00%	0.00%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**0.00%**
	INCOME TAXES			
10	Total Income Taxes	Attachment H-24A, p 3, line 27 col 5	-	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	0.00%	0.00%
	RETURN			
12	Return on Rate Base	Attachment H-24A, p 3, line 28 col 5	25,293,160	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	6.58%	6.58%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**6.58%**

Note

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-24A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-24A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-24A, page 3 line 12.

F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G The Network Upgrade Charge is the value to be used in PJM OATT Schedule 26.

H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in Attachment H-24A Appendix B, page 2, column 9.

For the 12 months ended 12/31/20__

East Kentucky Power Cooperative, Inc.
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-24A, Page 1, Line 5c											$0

Note Letter

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-24A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-24A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-24A, page 3 line 12.

F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G The Network Upgrade Charge is the value to be used in Schedule 26.

H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Rate Formula Template
Utilizing Attachment H-24A

East Kentucky Power Cooperative, Inc.
Calculation of Prior Year Transmission Revenue Requirement True-up Adjustment
To be completed in conjunction with Attachment H-24A

Line No.	(1)		(2)
	Reconciliation Adjustment for Transmission Revenue Requirements		
1	Actual Transmission Revenue Requirement for 12 Months Ended 12/31/20__ including True Up for 12 months ended 12/31/20__ (1)		$ -
2	Less: True Up Under/(Over) Recovery Adjustment for EKPC Appendix H-24A for 12 months ended 12/31/20__ (2)		$ -
3	Transmission revenue requirements for the 12 months ended12/31/20__	(Line 1 - Line 2)	$ -
4	Less: Actual Transmission Revenue Collected for 12 months Ended 12/31/20__(3)		$ -
5	True-Up Principal Under(Over) Recovery before Interest	(Line 3 - Line 4)	$ -
6	Monthly Interest Rate--Final FERC rate (4)		0.000%
7	Number of Months being Trued Up		0
8	Interest	(Line 5 x Line 6 x Line 7)	$ -
9	True Up Principal & Interest Under(Over) Recovery--Preliminary (5)	(Line 9 + Line 15)	$ -

Notes:
(1) Revenue requirement from Page 1 of 5, line 7 of Attachment H-24A for the referenced year.
(2) EKPC Attachment H-24A, page 1 of 5, Line 6a for the referenced recovery year
(3) Revenue received under PJM Tariff Schedules 7 and 8 under Attachment H-24A for the referenced year.
(4) See: *http://www.ferc.gov/legal/acct-matts/interest-rates.asp* for the appropriate Month
(5) Goes to Attachment H-24A , page 1 of 5, line 6a

Rate Formula Template
Utilizing Attachment H-24A

East Kentucky Power Cooperative, Inc.
Calculation of Prior Year Transmission Revenue Requirement True-up Adjustment
To be completed in conjunction with Attachment H-24A

Line No.	(1)		(2)	
	Reconciliation Adjustment for Schedule 1A Charges			
10	Actual Schedule 1A Costs for 12 Months Ended 12/31/20__ including True Up for 12 months ended 12/31/20__ (6)		$	-
11	Less: True Up Under/(Over) Recovery Adjustment for EKPC Sch. 1A for 12 months ended 12/31/20__ (7)		$	-
12	True-Up Principal Under(Over) Recovery before Interest	(Line 10 - Line 11)		$0.00
13	Less: Actual Sch. 1A Revenue Collected for 12 months Ended 12/31/20__ (8)			$0.00
14	True-Up Principal Under(Over) Recovery before Interest	(Line 12 - Line 13)	$	-
15	Monthly Interest Rate--Final FERC rate (9)			0.000%
16	Number of Months being Trued Up			0
17	Interest	(Line 5 x Line 6 x Line 7)	$	-
18	True Up Principal & Interest Under(Over) Recovery--Preliminary (10)	(Line 9 + Line 15)	$	-

Notes:
(6) Revenue requirement calculated using EKCP Attachment H-24A, Appendix A and actual cost information for the referenced year.
(7) EKPC Attachment H-24A, Appendix A, Line 6a for the referenced recovery year.
(8) Revenue received from PJM under PJM Tariff Schedules 7 and 8 for the EKPC Zone under Attachment H-24A for the referenced year.
(9) See: *http://www.ferc.gov/legal/acct-matts/interest-rates.asp* for the appropriate Month
10) Goes to Attachment H-24A, Appendix A, line 4.

East Kentucky Power Cooperative, Inc.
Depreciation Rates
Rates effective for year ending December 31, 20__

Line No.	FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D)
				%
			Transmission Plant (1)	
1	350	350010	Rights of Way (No depr on land)	-
2	353	353000	Station Equipment	0.000
3	353	353010	Station Equipment - ECS	0.000
4	354	354000	Towers and Fixtures - Trans Plant	0.000
5	355	355000	Poles & Fixtures	0.000
6	356	356000	Overhead Conductors & Devices	0.000
7	359	359000	Roads and Trails - Trans Plant	0.000
			General and Intangible Plant	
8	303	303000	Miscellaneous Intangible Plant	0.000
9	390	390000	Structures and Improvements - General Plant	0.000
10	391	391000	Office Furn & Equip - Gen Plant	0.000
11	391	391001	Office Furn & Equip - Peoplesoft	0.000
12	392	392000	Transportation Equipment	0.000
13	393	393000	Stores Equipment	0.000
14	394	394000	Tools, Shop & Garage Equipment	0.000
15	395	395000	Lab Equipment - General Plant	0.000
16	396	396000	Power Operated Equip - Gen Plant	0.000
17	397	397000	Communication Equipment - General Plant	0.000
18	397	397000	Communication Bldgs & Towers	0.000
19	397	397001	Communication Eq - ECS - General Plant	0.000
20	398	398000	Misc Equip - General Plant	0.000

NOTES:
(1) Depreciation Rates approved in KPSC Case No. ______________.

ATTACHMENT H-24B
EKPC FORMULA RATE IMPLEMENTATION PROTOCOLS[1]

DEFINITIONS

"Annual Transmission Revenue Requirements" means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.

"Annual Update" means the posting and informational filing submitted by EKPC on or before May15 of each year that sets forth the EKPC Cost of Service ("COS") for the subsequent Rate Year.

"Discovery Period" means the period after each annual Publication Date to serve information requests on EKPC as provided in these Protocols.

"First Rate Year" means the period that begins on June 1, 2013, and ends on May 31, 2014.

"Formal Challenge" means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission ("Commission") as provided in these Protocols.

"Formula Rate" means these Formula Rate Implementation Protocols (to be included as Attachment H-24B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.

"Formula Rate Template" means the collection of formulae and worksheets, unpopulated with any data, to be included as Attachment H-24A of the PJM Tariff.

"Preliminary Challenge" means a written challenge to the Annual Update submitted to EKPC as provided in these Protocols.

"Protocols" means these Formula Rate Implementation Protocols (to be included as Attachment H-24B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update.

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[1]East Kentucky Power Cooperative, Inc ("EKPC") is an electric cooperative with outstanding debt from the United States Rural Utilities Service, and is not a FERC-jurisdictional public utility as that term is used in the Federal Power Act, 18 U.S.C. 824(f). In submitting and complying with these procedures and the formula rate, EKPC is not waiving its non-jurisdictional status and is not submitting to the FERC's jurisdiction except to the extent that the

Commission by law has jurisdiction to review EKPC's rates by virtue of EKPC's participation in PJM.

SECTION 1 <u>Annual Updates</u>

a. Beginning with the First Rate Year and for each Rate Year thereafter, the Annual Transmission Revenue Requirement calculated in accordance with Attachment H-24A and the Network Integration Transmission Service and Point-to-Point rates derived from Attachment H-24A shall be applicable to transmission services provided by PJM for the EKPC transmission pricing zone during the Rate Year.

b. On or before April 30 of each year, EKPC shall recalculate its Annual Transmission Revenue Requirement, producing the "Annual Update" for the upcoming Rate Year. EKPC shall:

   (i) Arrange for PJM to post such Annual Update on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) as both a .pdf (Portable Document Format) document and a fully-functioning Excel file;

   (ii) Provide contact information for inquiries concerning the Annual Update;

   (iii) Send an email or other similar electronic communication to all parties affected by the Annual Update or which have previously requested such notification through procedures to be established by EKPC, informing the recipients that the Annual Update is available and providing the Uniform Resource Locator or other similar identifying location information from which the Annual Update can be obtained.

c. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the Commission, then the posting shall be due on the next business day.

d. The date on which the Annual Update is posted shall be that year's Publication Date.

e. Within two business days of the Publication Date, EKPC shall arrange for PJM to provide notice on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) of the time, date and location of an open meeting among interested parties ("Annual Meeting"). This Annual Meeting shall (i) permit EKPC to explain and clarify its Annual Update and (ii) provide interested parties an opportunity to seek information and clarifications from EKPC about the Annual Update. The Annual Meeting shall take place no sooner than ten (10) days after posting of the notice and no later than thirty (30) days after the Publication Date.

f. Inputs to the Formula Rate are based on EKPC's financial records and supporting work papers, which reflect:

   (i) The RUS's Uniform System of Accounts, and

   (ii) Applicable EKPC Form FF1[2] as each exists as of the later of the date of EKPC's initial filing of the Formula Rate or the last day of the calendar year immediately preceding the effective date of the most recent revision to the Formula Rate.

[2] EKPC is not a Public Utility as that term is used under the Federal Power Act and is therefore does not prepare or file a FERC Form No. 1 with the Commission. However, EKPC annually prepares a report on its finances and expenses containing information that matches that required for the FERC Form No. 1 and files that document with the Kentucky Public Service Commission. That document is designated as the EKPC Form FF1.

g. The Annual Update for the Rate Year:

(i) Shall, to the extent specified in the Formula Rate, be based upon the EKPC Form FF1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of EKPC consistent with Section 1.f above;

(ii) Shall, to the extent specified in the Formula Rate, provide the Formula Rate calculations and all inputs thereto, as well as support for data not otherwise available in the EKPC Form FF1 that are used in the Formula Rate;

(iii) Shall describe material changes, if any, in EKPC's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based that could or do materially affect the charges under the Formula Rate;

(iv) Shall be subject to challenge and review in accordance with the procedures set forth in this Attachment H-24B as to the appropriateness of the input data and the application of the Formula Rate according to its terms and the procedures in this Attachment H-24B;

(v) Except as provided for in Section 1.j below, shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate (i.e., all such modifications to the Formula Rate will require a filing with the FERC).

h. Formula Rate inputs for the Times Interest Earned Rate (TIER) and depreciation rates shall be stated values until changed pursuant to a filing made effective by the Commission.

SECTION 2 <u>Annual Review Procedures</u>

Each Annual Update shall be subject to the following Annual Review Procedures:

a. Interested parties shall have up to one hundred fifty (150) days after the Publication Date to review the inputs, supporting explanations, allocations and calculations ("Review

Period") and to notify EKPC in writing, which notification may be made electronically, of any specific challenges.

b. Interested Parties shall have up to one hundred twenty (120) days after each annual Publication Date to serve reasonable information requests on EKPC. Such information requests shall be limited to what is necessary to determine if EKPC has properly applied the Formula Rate and the procedures of this Attachment H-24B Formula.

c. EKPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests.

d. Preliminary Challenges shall be subject to the resolution procedures and limitations in Section 3. Formal Challenges shall be filed pursuant to these Protocols and shall include the information required under 18 C.F.R. § 385.206 (b) (1), (2), (3), (4), and (7).

e. Preliminary or Formal Challenges related to material changes are not intended to serve as a means of pursuing other objections to the Formula Rate. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.

SECTION 3 <u>Resolution of Challenges</u>

a. If EKPC and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of EKPC to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the Commission, which shall be served on EKPC by electronic service on the date of such filing.

b. In any proceeding initiated by the Commission concerning the Annual Update or in response to a Formal Challenge, EKPC shall bear the burden of proving that it has correctly applied the terms of the Formula Rate.

c. Each Annual Update shall become final as to the Annual Transmission Revenue Requirement calculated for the Rate Year for which the Annual Update was calculated and no longer subject to challenge pursuant to these Protocols on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and the Commission has not initiated a proceeding to consider the Annual Update, or (ii) a final Commission order issued in response to a Formal Challenge or a proceeding initiated by the Commission to consider the Annual Update.

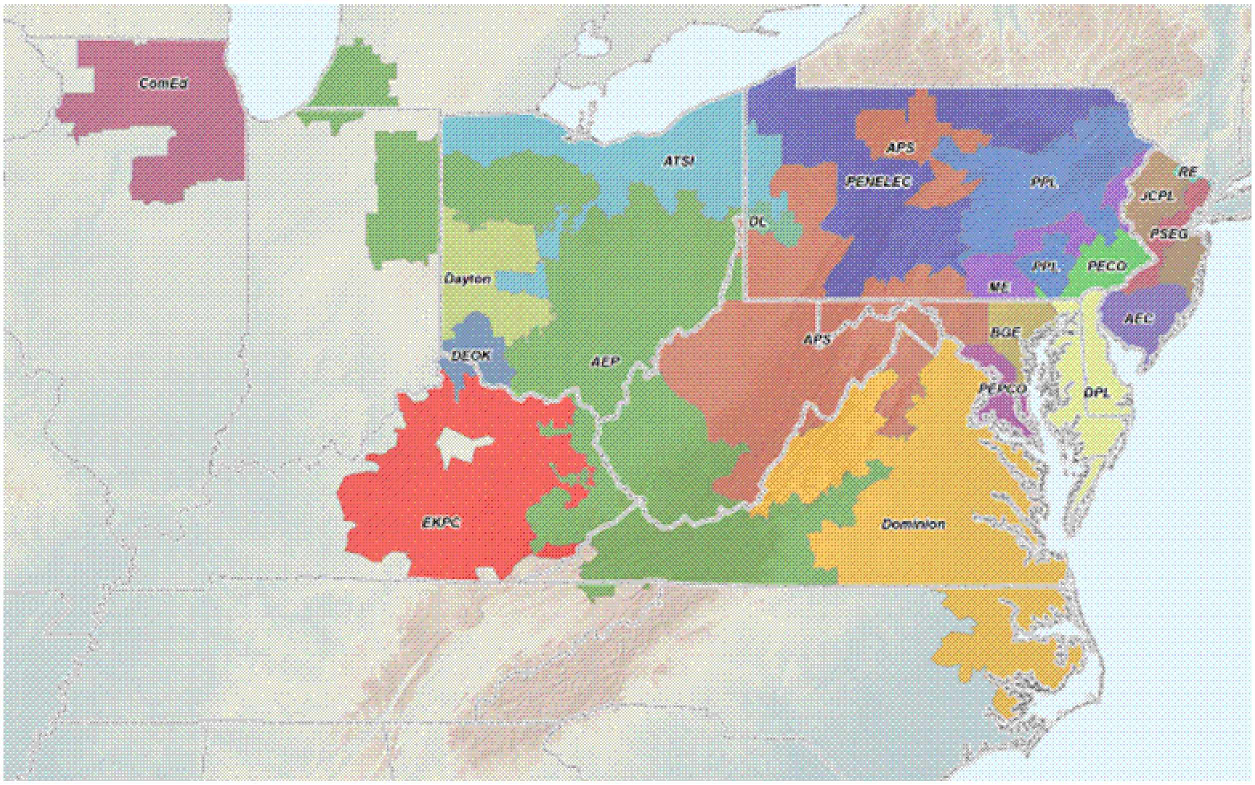
d. Except as specifically provided herein, nothing shall be deemed to limit in any way the right of EKPC to unilaterally file changes to the Formula Rate or any of its inputs (including, but not limited to, TIER or a replacement for TIER, transmission depreciation rates and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. These Protocols in no way limit the rights of EKPC or any Interested Party to initiate a proceeding at the Commission at any time with respect to the Formula Rate or any Annual Update consistent with the party's full rights under the FPA.

SECTION 4 Changes to Annual Informational Filings

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's EKPC Form FF1, or input data used for a Rate Year or calendar year that would have affected the Annual Update for that Rate Year or calendar year, or as the result of any Commission proceeding to consider a prior year's Annual Update, EKPC shall promptly notify the interested parties and provide a copy of the revised Annual Update to PJM for posting on the PJM's web site.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest.

ATTACHMENT J
PJM Transmission Zones



FULL NAME	SHORT NAME
Pennsylvania Electric Company	PENELEC
Allegheny Power	APS
PPL Electric Utilities Corporation	PPL
Metropolitan Edison Company	ME
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
Duquesne Light Company	DL
Virginia Electric and Power Company	Dominion
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK
East Kentucky Power Cooperative, Inc.	EKPC

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

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

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

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

3.2.2 Regulation.

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

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying* the assigned MW(s) by the performance Regulation market-clearing price, *by* the *ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources*, and *by* the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for

Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

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

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

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

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

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

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

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

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and
>
> where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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

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

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage.

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

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

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

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer

Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed \$1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

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

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

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$\text{Ramp\_Request}_t = \left(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}\right) \big/ \left(\text{UDSLAtime}_{t-1}\right)$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

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

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

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

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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

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

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

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants’ response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource’s expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-

Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non- Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the

Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

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

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the

Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

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

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

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

3.2.7 Billing.

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

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

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; 2013 for the EKPC Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each

historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Prior to the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights allocated at the aggregate load buses in a Zone. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section

7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Prior to the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights sink at the aggregate load buses in a Zone. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under

contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web

site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

ATTACHMENT L
List of Transmission Owners

Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Atlantic City Electric Company
Baltimore Gas and Electric Company
NAEA Rock Springs, LLC
Delmarva Power & Light Company
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
East Kentucky Power Cooperative, Inc.
Hudson Transmission Partners, LLC
Jersey Central Power & Light Company
Metropolitan Edison Company
Neptune Regional Transmission System, LLC
Old Dominion Electric Cooperative
Pennsylvania Electric Company
PECO Energy Company
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Trans-Allegheny Interstate Line Company
UGI Utilities, Inc.
Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power
Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.
The Dayton Power and Light Company
AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)
Duquesne Light Company
Virginia Electric and Power Company
Linden VFT, LLC
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Hamilton, OH

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin (“IRM”)% minus 3%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target ; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency

Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2015, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $128,000 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	140,000
BGE, PEPCO ("CONE Area 2")	130,600
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC ("CONE Area 3")	127,500
PPL, MetEd, Penelec ("CONE Area 4")	134,500
Dominion ("CONE Area 5")	114,500

B) Beginning with the 2016-2017 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2015-2016 Delivery Year to which the Applicable H-W Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under

the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the Zone in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Section(s) of the
PJM Operating Agreement

(Clean Format)

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

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

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

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

3.2.2 Regulation.

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

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying* the assigned MW(s) by the performance Regulation market-clearing price, *by* the *ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources*, and *by* the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

$$\text{Error} = \text{Average of Abs}\left((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})\right); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the

Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing

Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

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

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

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

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

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

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

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

> LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in

which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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

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

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage.

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

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

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

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

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

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

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$\text{Ramp\_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLAtime}_{t-1})}$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

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

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

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

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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

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

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

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve

Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

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

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

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

where:

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

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

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

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

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

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance

Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

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

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

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

3.2.7 Billing.

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

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

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; 2013 for the EKPC Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each

historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Prior to the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights allocated at the aggregate load buses in a Zone. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section

7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Prior to the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights sink at the aggregate load buses in a Zone. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under

contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web

site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer’s Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer’s Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer’s network service peak load; or 2) the customer’s Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

SCHEDULE 12 -
PJM MEMBER LIST

A123 Systems, Inc.
AC Energy, LLC
AC Power Financial Corp.
Acciona Energy North America Corporation (AENAC)
A&C Management Group LLC
AEP Appalachian Transmission Company, Inc.
AEP Energy, Inc.
AEP Energy Partners, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP Retail Energy Partners, LLC
AEP West Virginia Transmission Company, Inc.
AES Armenia Mountain Wind, LLC
AES Beaver Valley LLC
AES Energy Storage, LLC
AES Laurel Mountain, LLC
Agway Energy Services, LLC
Air Liquide Industrial US, LP
Air Products & Chemicals, Inc.
AK Steel Corporation
Akula Energy, LLC
Alabama Power Company
Alcoa Power Marketing LLC
Algonquin Energy Services, Inc.
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, LLC
ALLETE, Inc. d/b/a Minnesota Power
Alliant Energy Corporate Services, Inc.
Alpha Gas and Electric, LLC
Ambit Northeast, LLC
Ameren Energy Marketing Company
American Efficient, Inc.
American Illuminating Company, LLC
American Municipal Power, Inc.
American Power Partners, LLC
American PowerNet Management, L.P.
American Transmission Company, LLC
American Transmission Systems Inc.
Amerigreeen Energy, Inc.
Anbaric Northeast Transmission Development Company, LLC
AP Gas & Electric (IL), LLC

AP Gas & Electric (MD), LLC
AP Gas & Electric (OH), LLC
AP Gas and Electric (NJ), LLC
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Appalachian Power Company
Apple Group LLC
APX Power Markets, Inc.
Aquenergy Systems Inc.
Aquila, Inc. d/b/a Aquila Networks
ArcelorMittal USA, LLC
ArcLight Energy Marketing, L.L.C.
Aspen Merchant Energy, LP
Associated Electric Cooperative, Inc.
Astral Energy LLC
Atlantic City Electric Company
Atlantic Grid Operations A, LLC
Automated Algorithms, LLC
Balance Power Systems, LLC
Baltimore Gas and Electric Company
Bank of America N.A.
Barclays Bank PLCBE Red Oak LLC
Barclays Capital Services, Inc
Bartram Lane, LLC
BBPC LLC d/b/a/ Great Eastern Energy
Beacon Power Corporation
Beech Ridge Energy LLC
Benton Foundry, Inc.
BG Energy Merchants, LLC
Big Rivers Electric Corporation
Big Sandy Peaker Plant, LLC
Big Savage, LLC
Big Sky Wind, LLC
Biogas Energy Solutions LLC
Bishop Hill Energy LLC
BJ Energy, LLC
Black Oak Capital, LLC
Black Oak Energy, LLC
Black River Commodity Energy Fund LLC
Black River Commodity Fund, Ltd.
Blackstone Wind Farm, LLC
Blackstone Wind Farm II, LLC
Blast Electric, LLC
Bluefin Electricity Trading, LLC
Bluegrass Generating Company, LLC
Blue Pilot Energy, LLC

Blue Ridge Power Agency, Inc.
BNP Paribas Energy Trading GP
Border Energy Electric Services, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Lavallette, New Jersey
Borough of Madison, New Jersey
Borough of Milltown
Borough of Mont Alto
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights
Borough of South River, New Jersey
Borough of Tarentum
Bounce Energy PA, LLC
BP Alternative Energy North America Inc.
BP Energy Company
Brighten Energy, LLC
Brookfield Energy Marketing Inc.
Brookfield Energy Marketing, LP
Brookfield Power Piney & Deep Creek LLC
Brookfield Renewable Energy Marketing US LLC
Bruce Power Inc.
Buckeye Power, Inc.
Buckeye Energy Brokers, Inc.
Calpine Bethlehem, LLC
Calpine Energy Services, L.P.
Calpine Mid Atlantic Marketing, LLC
Calvert Cliffs Nuclear Power Plant, Inc.
Cambria Cogen Company
Camp Grove Wind Farm, LLC
Canadian Wood Products – Montreal, Inc. dba CWP Energy
Cargill Power Markets, LLC
Carolina Power & Light Company
Castlebridge Energy Group, LLC
Cayler Trading Group, LLC
CBK Group, LTD
CCES LLC
Centaurus Energy Master Fund, LP
Central Transmission, LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy, LLC
Champion Energy Marketing LLC
Champion Energy Services, LLC

Chesapeake Transmission LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Cincinnati Bell Energy, LLC
Cinergy Retail Sales, LLC
Cinnamon Bay, LLC
Citigroup Energy Inc.
Citizen's Electric Company of Lewisburg, PA
City of Batavia, Illinois
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Geneva (The)
City of Hamilton
City of New Martinsville – WV
City of Naperville
City of Philadelphia
City of Philippi – West VA
City of Rochelle
CleanLight Power + Energy, LLC
Clearview Electric, Inc.
Cleveland Electric Illuminating Company (The)
CMS Energy Resource Management Company
Coaltrain Energy LP
Cobalt Capital Partners, LLC
Cogentrix Virginia Leasing Corporation
Commercial Utility Consultants, Inc.
Commerce Energy Inc.
Commonwealth Chesapeake Company, LLC
Commonwealth Edison Company
Community Energy, Inc.
Comperio Energy LLC dba ClearChoice Energy
Con Edison Energy, Inc.
Conch Energy Trading, LLC
Conectiv Energy Supply, Inc.
ConocoPhillips Company
Consolidated Edison Company of New York, Inc.
Consolidated Edison Solutions, Inc.
Constellation Energy Commodities Group, Inc.
Constellation Energy Control and Dispatch, LLC
Constellation Energy Power Choice, Inc.
Constellation Energy Projects & Services Group, Inc.
Constellation NewEnergy, Inc.
Constellation Power Source Generation, Inc.
Consumers Energy Company
Coral Power, L.L.C.
Cordova Energy Company LLC
CornerStone Power Development, LLC

Corona Power LLC
Corporate Services Support Corp.
County of Frederick, VA
Covanta Delaware Valley, L.P.
Covanta Energy Group, Inc.
Covanta Essex Company
Covanta Union, Inc.
CP Energy Marketing (US) Inc.
CPV MARYLAND, LLC
CPV Shore, LLC
Credit Suisse Energy LLC
Credit Suisse (USA), Inc.
Crete Energy Venture, LLC
CrunchEnergy, LLC
Customized Energy Solutions, Ltd.
Cygnus Energy Futures, LLC
Darby Energy, LLLP
Dart Container Corporation of Pennsylvania
Dayton Power & Light Company (The)
DB Energy Trading LLC
DC Energy LLC
DC Energy Mid-Atlantic, LLC
DEL LIGHT INC.
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Demand Response Partners, Inc.
Demansys Energy, LLC
Denver Energy, LLC
Devonshire Energy, LLC
Diamond State Generation Partners, LLC
Direct Energy Business, LLC
Direct Energy Services, LLC
Discount Energy Group, LLC
Discount Energy, LLC
Discount Power, Inc.
Divine Power, Inc.
Division of the Public Advocate of State of Delaware
Dominion Energy Marketing, Inc.
Dominion Retail, Inc.
Domtar Paper Company, LLC
Downes Associates, Inc.
DPL Energy, LLC
DPL Energy Resources, LLC
DTE Energy Supply, Inc.
DTE Energy Trading, Inc.
Duke Energy Carolinas, LLC

Duke Energy Commercial Asset Management
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Shared Services, Inc.
Duquesne Conemaugh LLC
Duquesne Keystone LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Duquesne Power LLC
DynArb, LLC
Dynasty Power Inc.
Dynegy Energy Services, Inc.
Dynegy Marketing and Trade, LLC
Dynegy Power Marketing, Inc.
Dyon, LLC
E Minus LLC
E.ON Climate & Renewables North America Inc.
Eagle Energy, LLC
Eagle Point Power Generation LLC
East Coast Power Linden Holdings, L.L.C.
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
Ebensburg Power Company
eCap Network, LLC
EcoGrove Wind, LLC
EDF Industrial Power Services (IL), LLC
EDF Trading North America, LLC
Edison Mission Marketing & Trading, Inc.
Edison Mission Solutions, LLC
EDP Renewables North America, LLC
E.F. Kenilworth, Inc.
EFS Parlin Holdings, LLC
El Cap II, LLC
Elkem Metals Company-Alloy LP
El Paso Marketing, LLC
Elliot Bay Energy Trading, LLC
Elwood Energy LLC
EMC Development Company, Inc.
EME Homer City Generation, L.P.
Emera Energy Services, Inc.
Employers' Energy Alliance of Pennsylvania, Inc.
Emporia Hydropower Limited Partnership
ENBALA Power Networks, Inc.
Endure Energy, LLC
Energetix, Inc.
Energy America, LLC

Energy Algorithms LLC
Energy Analytics
Energy Analytics, Inc.
Energy Authority, Inc. (The)
EnergyConnect, Inc.
Energy Consulting Services, LLC
Energy Cooperative of America, Inc.
Energy Cooperative Association of Pennsylvania
Energy Curtailment Specialists, Inc. (ECS)
Energy Exchange Direct, LLC
Energy Exchange International, LLC
Energy International Power Marketing Corporation
Energy Investments, LLC
Energy-Links, LLC
Energy.me Midwest llc d/b/a energy.me
Energy Plus Holdings LLC
Energy Service Providers, Inc.
Energy Spectrum Inc.
EnergyUSA – TPC Corp.
EnerNOC, Inc.
EnerPenn USA, LLC
Enerwise Global Technologies, Inc.
Engage Energy America LLC
Enserco Energy, Inc.
Entegra Power Services LLC
EP Enterprises Incorporated
EP Ocean Peaking Power, LLC
EP Rock Spring, LLC
EPEX, Inc.
EPIC NJ/PA, L.P.
ERA MA, LLC
Essential Power, LLC
Ethical Electric Benefit Co.
Evergreen Community Power
Evraz Claymont Steel
Exel Power Sources, LLC
Exelon Business Services Company, LLC
Exelon Energy Company (The)
Exelon Generation Company, LLC
Exelon New England Power Marketing, Limited Partnership
Falcon Energy, LLC
FirstEnergy Solutions Corp.
First Point Power, LLC
Florida Power Corporation dba Progress Energy Florida, Inc.
Forest Investment Group, LLC
Fowler Ridge Wind Farm LLC

Fowler Ridge II Wind Farm LLC
FPL Energy Marcus Hook LP
Franklin Power LLC
Freepoint Commodities LLC
Fulcrum Energy Limited
Galt Power, Inc.
Gateway Energy Services Corporation
GDF SUEZ Energy Resources NA, Inc.
GDF Suez Retail Energy Solutions, LLC
Gelber Energy LLC
GenOn Energy Management, LLC
GenOn Potomac River, LLC
GenOn Power Midwest, LP
Georgia Power Company
Gerdau Ameristeel Energy, Inc
Glacial Energy of New Jersey, Inc.
Grand Ridge Energy LLC
Grand Ridge Energy II LLC
Grand Ridge Energy III LLC
Grand Ridge Energy IV LLC
Grand Ridge Energy V LLC
Granger Energy of Honey Brook, LLC
Grant Energy, Inc.
Grays Ferry Cogeneration Partnership
Great American Power, LLC
Great Bay Energy I, LLC
Great Bear Hydropower, Inc.
Green Mountain Energy Company
Greenpoint Trading Group, LLC
GRG ENERGY LLC
GSG 6, LLC
Gulf Power Company
G&G Energy, Inc.
Hagerstown Light Department
Handsome Lake Energy, LLC
Harrison REA, Inc. – Clarkesburg, WV
Hartz Group (The)
Hawks Nest Hydro LLC
Hazleton Generation LLC
Hemsworth Capital LP
Hess Corporation
Hess NEC, LLC
Hexis Energy Trading, LLC
Highland North LLC
Highlands Energy Group, LLC (The)
HIKO Energy, LLC

Hill Energy Resource & Services, LLC
Holcim (US), Inc.
Hoosier Energy REC, Inc.
HOP Energy, LLC
Horizon Power and Light, LLC
H-P Energy Resources, LLC
H.Q. Energy Services (U.S.), Inc.
HSBC Technology Services (USA), Inc.
Hudson Energy Services, LLC
Hudson Transmission Partners, LLC
Iberdrola Renewables, LLC
Icetec.com, Inc.
IDT Energy, Inc.
Illinois Citizens Utility Board
Illinois Municipal Electric Agency
Independence Energy Group, LLC
Independent Energy Consultants, Inc.
Indiana Michigan Power Company
Indiana Municipal Power Agency
Indiana Office of Utility Consumer Counselor (IN OUCC)
Industrial Energy Users-Ohio
Industrial Metal Treating Corp.
Ingenco Wholesale Power, LLC
Innoventive Power LLC
Integrys Energy Services, Inc.
IntelliGen Resources, LP
Intergrid Mideast Group LLC
International Paper Company
Interstate Gas Supply, Inc.
Interstate Power and Light Company
Invenergy LLC
Invenergy Nelson LLC
Invictus Capital Management, Ltd
IPR-GDF Suez Energy Marketing North America, Inc.
Iron Energy LLC
J. Aron & Company
J3 Energy Group (The)
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
JAS Energy, LLC
James River Cogeneration Company
Jersey-Atlantic Wind, LLC
Jersey Central Power & Light Company
Jersey Green Energy, LLC
JP Morgan Ventures Energy Corporation
JPTC, LLC
Juice Technologies, LLC

Kansas City Power & Light
KAP Analytics, LLC
Kasia C LLC
Katmai Energy, LLC
Keil & Sons, Inc dba Systrum Energy
Kentucky Municipal Power Agency
Kentucky Power Company
KeyTex Energy LLC
KeyTex Energy Solutions LLC
KFW Energy, LLC
Kimberly-Clark Corporation
Kimmel Energy Associates
Kingsport Power Company
Knedergy, LLC
KOREnergy, Ltd.
Krayn Wind LLC
Kuehne Chemical Company, Inc.
Kynetic Energy Solutions L&P Electric Inc., dba Leggett & Platt Electric Inc.
LCG Consulting
LDH Energy Funds Trading, Ltd.
Lee River Proprietary Strategies, Inc.
Legacy Energy Group, LLC (The)
Legends Energy Group, Inc.
Lehigh Capital, LLC
Lehigh Portland Cement Company
Lehman Brothers Commodity Services, Inc.
Letterkenny Industrial Development Authority – PA
Liberty Electric Power, LLC
Liberty Hill Power LLC
Liberty Power Corp., L.L.C.
Liberty Power Delaware, LLC
Liberty Power District of Columbia LLC
Liberty Power Holdings LLC
Liberty Power Maryland, LLC
Lilabell Energy LLC
Lincoln Generating Facility, LLC
Linde, Inc.
Linde Energy Services, Inc.
Linden VFT LLC
LM Power, LLC
Long Island Lighting Company d/b/a LIPA
Longview Power, LLC
Louis Dreyfus Energy Services L.P.
Louisville Gas and Electric Company/Kentucky Utilities Company
Lower Electric, LLC
Lower Mount Bethel Energy, LLC

LSP-Kendall Energy, LLC
LSP Safe Harbor Holdings, LLC
LSP University Park, LLC
Luminary Consulting LLC
Mac Trading, Inc.
Macquarie Energy, LLC
Madison Gas and Electric Co.
Madison Windpower LLC
MAG Energy Solution, Inc.
Magnolia Energy, LP
Major Energy Electric Services, LLCMaple Analytics, LLC
Marathon Power, LLC
Marina Energy, LLC
Maryland Office of People's Counsel
MC Squared Energy Services, LLC
MeadWestvaco Corporation
Meadow Lake Wind Farm, LLC
Meadow Lake Wind Farm II, LLC
Meadow Lake Wind Farm III, LLC
Meadow Lake Wind Farm IV, LLC
MEG Generating Company, LLC
Mehoopany Wind Energy LLC
Mercuria Energy America, Inc.
Merrill Lynch Commodities, Inc.
MET MA LLC
Metropolitan Edison Company
Metropolitan Energy, L.L.C.
Miami Valley Lighting, LLC
Michigan Public Power Agency
Microsoft Corporation
MidAmerican Energy Company
MidAtlantic Power Partners
Middlesex County Utilities Authorities
Midwest Energy Trading East LLC
Midwest Generation, LLC
Millennium Inorganic Chemicals, Inc.
Mint Energy, LLC
Mississippi Power Company
Monmouth Energy, Inc.
Monongahela Power Company d/b/a/ Allegheny Power
Monterey MA, LLC
Monterey MAF, LLC
Morgan Stanley Capital Group, Inc.
Morris Cogeneration, L.L.C Mt. Carmel Cogeneration Inc.
Morse Energy LLC
Mosaic Power, LLC

Moxie Liberty LLC
MP2 Energy NE, LLC
NASDAQ OMX Commodities Clearing, LLC
Natgasco, Inc.
National Railroad Passenger Corp. – AMTRAK
Nautilus Solar Energy, LLC
NedPower Mount Storm, LLC
Negawatt Business Solutions, Inc.
NEPM II, LLC
Neptune Regional Transmission System, LLC
NERC-Middlesex Solar I, LLC
New Covert Generating Company, LLC
New Jersey Division of the Ratepayer Advocate
New York State Electric & Gas Corporation
Newel Trading Group, LLC
NextEra Energy Power Marketing, LLC
NextEra Energy Services Illinois, LLC
NextEra Energy Services New Jersey, LLC
NJR Clean Energy Ventures Corporation
Noble American Gas & Power Corp.
Noble Americas Energy Solutions, LLC
Nordic Energy Services LLC
North America Power Partners LLC
North American Energy Credit and Clearing-Delivery LLC
North American Natural Resources – SBL, LLC
North American Power and Gas, LLC
Northampton Generating Company
Northeast Maryland Waste Disposal Authority
Northeast Transmission Development, LLC
Northeastern REMC
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northeast Utilities Service Company
Northern Illinois Municipal Power Agency
Northern States Power Company
Northern Virginia Electric Cooperative - NOVEC
NorthPoint Energy Solutions, Inc.
Northport USA, LLC
NorthWrite Energy Group, LLC
NRG Power Marketing, LLC
NuEnergen, LLC
NYSEG Solutions, Inc.
NYX Energy Corp.
Oasis Power, LLC dba Oasis Energy
Occidental Power Services, Inc.
Oceanside Power, LLC

Office of the People's Counsel for the District of Columbia
Ohio Consumer's Counsel
Ohio Edison Company
Ohio Power Company
Ohms Energy Company, LLC
Old Dominion Electric Cooperative
Olympus Power, LLC
Ontario Power Generation Inc.
Ontario Power Generation Energy Trading, Inc.
Ontelaunee Power Operating Company, LLC
Orion Asset Management, LLC
Owensboro Municipal Utilities
Ozark International, Inc.
P.H. Glatfelter Company
Pacific Summit Energy LLC
Palama, LLC
Palmco Power DC, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power OH, LLC
Palcom Power PA, LLC
Panda Power Corporation
Panther Creek Power Operating, LLC
Parma Energy LLC
PATH Allegheny Transmission Company, LLC
PATH West Virginia Transmission Company, LLC
Pattern Recognition Technologies, Inc.
Patton Wind Farm, LLC
Paulding Wind Farm II LLC
PBF Power Marketing, LLC
PECO Energy Company
Pedricktown Plant Holdings, LLC
PEI Power Corporation
PEI Power II, LLC
Penncat Corporation
Pennsylvania Electric Company
Pennsylvania Office of Consumer Advocate
Pennsylvania Power Company
Pennsylvania Renewable Resources, Associates
People's Power & Gas, LLC
Pepco Energy Services, Inc.
Perspective Energy USA LLC
PG Energy Services Inc. d/b/a/ PG Energy Power Plus
Phalanx Energy Services, LLC
Pioneer Prairie Wind Farm, LLC

Pirin Solutions, Inc.
PJS Capital, LLC
Planet Energy (Maryland) Corp.
Planet Energy (Pennsylvania) Corp.
Planet Energy (USA) Corp.
Plymouth Rock Energy, LLC
Potomac Edison Company (The) d/b/a/ Allegheny Power
Potomac Electric Power Company
Potomac Power Resources, Inc.
Powerex Corporation
PowerSecure, Inc.
PPL Brunner Island, LLC
PPL Electric Utilities Corporation dba PPL Utilities
PPL EnergyPlus, LLC
PPL EnergyPlus Retail, LLC
PPL Holtwood, LLC
PPL Ironwood, LLC
PPL Martins Creek, LLC
PPL Montour, LLC
PPL Susquehanna, LLC
Prairieland Energy, Inc.
Praxair, Inc.
Premcor Refining Group, Inc. (The)
Primary Power, LLC
Procter & Gamble Paper Products Company (The)
Property Endeavors LLC
Providence Heights Wind, LLC
PSEG Energy Resources & Trade LLC
Public Power & Utility of Maryland, LLC
Public Power & Utility of New Jersey, LLC
Public Power, LLC
Public Power, LLC [CT]
Public Service Electric and Gas Company
Pure Energy, Inc.
Quasar Energy Group, LLC
Quiet Light Trading, LLC
QVINTA, Incorporated
Raiden Commodities LP
Rainbow Energy Marketing Corporation
Rational Systems LLC
RBC Energy Services LP
RC Cape May Holdings, LLC
Realgy, LLC
Red Oak Power, LLC
Red Wolf Energy Trading, LLC
Reliable Power, LLCReliant Energy Electric Solutions, LLC

Reliant Energy Northeast, LLC
Reliant Energy Services, Inc.
Reliant Energy Solutions East, LLC
Renaissance Power, LLC
ResCom Energy, LLC
Reservoir Creek Energy, L.P.
Respond Power, LLC
RG Steel Sparrows Point, LLC
RI-Corp. Develement, Inc.
Richards' Energy Group (The)
Richland-Stryker Generation LLC
Riverside Generating Company, L.L.C.
RLTec US Inc.
Rochester Gas and Electric Corporation
Rockland Electric Company
Rolling Hills Generating, L.L.C.
Roth Rock Wind Farm, LLC
Royal Bank of Canada
RRI Energy Services, LLC
S.J. Energy Partners, Inc.
Safe Harbor Water Power Corporation
Safeway Inc.
Sailor's Star Co.
Santana Energy Services
Saracen Energy East LLC
Saracen Energy Power Trading LP
Saracen Power LLC
Schuylkill Energy Resources, Inc.
Scylla Energy LLC
Select Energy New York, Inc.
Sempra Generation
Servidyne Systems, LLC
SESCO ENTERPRISES LLC
Sheetz, Inc.
Siemens Energy, Inc.
SIG Energy, LLLP
Site Controls, Inc.
Smart Grid Solutions, LLC
SMART Papers Holdings, LLC
Smart Wire Grid, Inc.
Solios Power LLC
Solios Power Mid-Atlantic Trading, LLC
Solios Power Mid-Atlantic Virtual LLC
South Carolina Electric & Gas Company
Southeastern Chester County Refuse Authority
Southeastern Power Administration

Southern Indian Gas and Electric Company d/b/a Vectren Power Supply Inc.
Southern Power Company
Southern Maryland Electric Cooperative, Inc.
South Jersey Energy Company
South Jersey Energy Solutions, L.L.C.
Spark Energy, L.P.
Sperian Energy Corp
Starion Energy PA, Inc.
STATARB INVESTMENTS LLC
Stoney Creek Wind Farm, LLC
Strategic Transmission LLC
Stream Energy Columbia, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
STS Energy Partners LP
Sugar Creek Power Company, LLC
Summit Energy, LLC
SunCoke Energy, Inc
Sunoco, Inc. (R&M)
Sunoco Power Marketing, L.L.C.
Superior Plus Energy Services, Inc.
Sustainable Star LLC
Syncarpha Solar, LLC
Synergy Solutions Group LLC
Tangent Energy Solutions, Inc.
TAQA Gen X LLC
Target Corporation
TEC Trading, Inc.
Telemagine, Inc.
Tenaska Power Services Co.
Tenaska Virginia Parners, L.P.
Tennessee Valley Authority (The)
TERM Power & Gas, LLC
Texas Retail Energy, LLC
Thomas Jackson Management, Inc.
Thurmont Municipal Light Company
Tilton Energy, LLC
Titan Gas and Power
Toledo Edison Company (The)
Torofino Trading, LLC
Town of Berlin, Maryland
Town of Front Royal, Virginia
Town of Williamsport
Trademark Merchant Energy, LLC
Traditum Group LLC

Trans-Allegheny Interstate Line Company
TransAlta Energy Marketing (US) Inc.
TransCanada Power Marketing, Ltd.
Trans-Elect Development Company, LLC
TransMarket Group LLCUBS AG, acting through its London Branch
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trinity Powerworks, Inc.
TrueLight Commodities, LLC
Trumpet Trading Group, LLC
Trustees of the University of Pennsylvania, a Pennsylvania Non-Profit Corporation d/b/a University of Pennsylvania, The
Twin Cities Energy, LLC
Twin Cities Power, LLC
Twin Eagle Resource Management, LLC
UGI Development Company
UGI Energy Services, Inc.
UGI Utilities, Inc.
Union Electric Company d/b/a Ameren Missouri
Union Power Partners, L.P.
University Park Energy, LLC
U.S. Energy Partners dba PAETEC Energy
U.S. Energy Services, Inc.
UtiliTech, Inc.
Utility Advantage, LLC
Valero Power Marketing, LLC
VCharge, Inc.
Velocity American Energy Master I, LP
Vel Energy, LLC
Verde Energy USA, Inc.
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verisae, Inc.
Vette Energy, LLC
Vineland Municipal Electric Utility
Viridian Energy PA, LLC
Viridity Energy, Inc.
Virginia Division of Consumer Counsel
Virginia Electric and Power Company
Virginia State Corporation Commission
Vision Power, LLC
Vitol, Inc.
Vlast LLC
VMAC LLC
Wabash Valley Power Association, Inc.

Washington Gas Energy Services, Inc.
Webenergy.net, Inc. d/b/a Consumer Powerline
Wellsboro Electric Company
Wells Fargo Commodities, LLCWestar Energy, Inc.
West Deptford Energy, LLC
West Deptford Energy II, LLCWest Oaks Energy LP
West Penn Power Company d/b/a/ Allegheny Power
West Virginia Consumer Advocate Division
Western Reserve Energy Services, LLC
Wheelabrator Frackville Energy Co Inc.
Wheelabrator Portsmouth, Inc.
Wheeling Power Company
Wildcat Wind Farm I, LLC
Windy Bay Power LLC
Wisconsin Electric Power Company
Wisconsin Power and Light Company
Wisconsin Public Power, Inc.
Wolf Hills Energy, LLC
Wolverine Power Supply Cooperative, Inc.
Wolverine Trading, LLC
Woodway Energy Partners, LLC
WPS Westwood Generation, LLC
XO Energy CAL2 LP
XO Energy MA, LP
XO Energy MA2, LP
XO Energy NY2 LP
Xoom Energy, LLC
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
York Generation Company LLC
Your Energy Holdings, LLC
Zacho Energy Trading, LLC.
Zongyi Solar America Co. Ltd.

Section(s) of the
PJM Reliability Assurance Agreement

(Clean Format)

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:

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

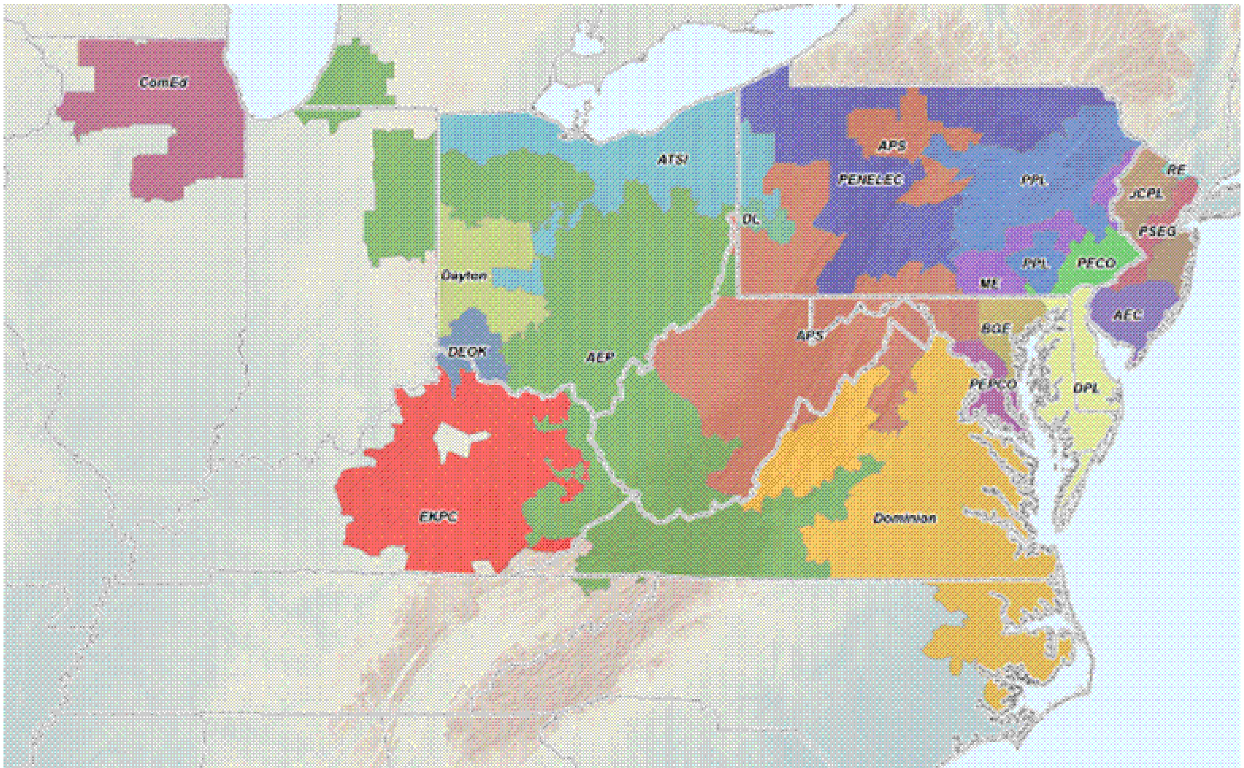
The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into

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.

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
East Kentucky Power Cooperative, Inc.	EKPC

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Energy, Inc.
AEP Retail Energy Partners LLC
Agway Energy Services, 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
    Indiana Michigan Power Company
    Kentucky Power Company
    Kingsport Power Company
    Ohio Power Company
    Wheeling Power Company.
American Illuminating Company, LLC
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
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.
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
Choice Energy, LLC dba 4 Choice 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.
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
Eagle Energy, LLC
East Kentucky Power Cooperative, Inc.
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.me Midwest llc d/b/a energy.me
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
Iron Energy LLC
J. Aron & Company
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jersey Central Power & Light Company
Keil and Sons, Inc. dba Systrum Energy
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
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.
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 DC, LLC
Palmco Power IL, LLC
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
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
Red Oak Power, 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
Titan Gas and Power
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
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, 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

Section(s) of the PJM Consolidated Transmission Owners Agreement

(Clean Format)

ATTACHMENT A

TO THE CONSOLIDATED

TRANSMISSION OWNERS AGREEMENT

Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power

American Electric Power Service Corporation on behalf of its operating companies: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company

Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.

Dayton Power and Light Company

Virginia Electric and Power Company (Dominion Virginia Power)

Public Service Electric and Gas Company

PECO Energy Company

PPL Electric Utilities Corporation

Baltimore Gas and Electric Company

Jersey Central Power & Light Company

Metropolitan Edison Company

Pennsylvania Electric Company

Potomac Electric Power Company

Atlantic City Electric Company

Delmarva Power & Light Company

UGI Utilities, Inc.

Allegheny Electric Cooperative, Inc.

CED Rock Springs, LLC

Old Dominion Electric Cooperative

Rockland Electric Company

Duquesne Light Company

Neptune Regional Transmission System, LLC

Trans-Allegheny Interstate Line Company

Linden VFT, LLC

American Transmission Systems, Incorporated

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power

Duke Energy Ohio, Inc.

Duke Energy Kentucky, Inc.

City of Hamilton, OH

Hudson Transmission Partners, LLC

East Kentucky Power Cooperative, Inc.

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

PJM Interconnection, L.L.C.

By: ___________________________________
Name: Phillip G. Harris
Title: President and CEO
Date: December 15, 2005

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

Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power

By: ______________________________
Name: James R. Haney
Title: Vice President
Date: December 15, 2005

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

American Electric Power Service Corporation

By:_________________________________
Name:
Title:
Date: December 15, 2005

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

Exelon Corporation on behalf of its subsidiaries
Commonwealth Edison Company and Commonwealth Edison
Company of Indiana, Inc.

By:__________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

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

The Dayton Power and Light Company

By: ___________________________________
Name: Patricia K. Swanke
Title: Vice President - Operations
Date: December 15, 2005

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

Virginia Electric and Power Company (Dominion Virginia Power)

By:__________________________________
Name: Gary L. Sypolt
Title: President – Dominion Transmission
Date: December 15, 2005

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

Public Service Electric and Gas Company

By: ___________________________________
Name: Ralph LaRossa
Title: Vice President - Electric Delivery
Date: December 15, 2005

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

Exelon Corporation on behalf of its subsidiary
PECO Energy Company

By:________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

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

PPL Electric Utilities Corporation

By:___________________________________
Name: John F. Sipics
Title: President
Date: December 15, 2005

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

Baltimore Gas and Electric Company

By:_____________________________
Name: Mark P. Huston
Title: Vice President, Electric Transmission and Distribution
Date: December 15, 2005

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

Jersey Central Power & Light Company

By: ________________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

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

Metropolitan Edison Company

By:________________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

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

Pennsylvania Electric Company

By:______________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

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

Potomac Electric Power Company

By:______________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

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

Atlantic City Electric Company

By: ________________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

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

Delmarva Power & Light Company

By:_________________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

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

UGI Utilities, Inc.

By: ____________________________
Name: Richard E. Gill
Title: Assistant Secretary - Electric Transmission
Date: December 15, 2005

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

CED Rock Springs, LLC

By:________________________________
Name:
Title:
Date: December 15, 2005

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

Old Dominion Electric Cooperative

By:________________________________
Name:
Title:
Date: December 15, 2005

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

Rockland Electric Company

By:_________________________________
Name:
Title:
Date: December 15, 2005

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

Duquesne Light Company

By:______________________________
Name:
Title:
Date: December 15, 2005

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

Allegheny Electric Cooperative, Inc.

By: ________________________________
Name: Richard W. Osborne
Title: Vice President Power Supply & Engineering
Date: December 15, 2005

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

Neptune Regional Transmission System, LLC

By: ________________________________
Name: Edward M. Stern
Title: CEO
Date: March 7, 2007

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

Trans-Allegheny Interstate Line Company

By: ________________________________
Name: James R. Haney
Title: Vice President
Date: November 8, 2007

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

Linden VFT, LLC

By: ___________________________________
Name: Andrew J. Keleman
Title: Authorized Representative
Date: April 1, 2009

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

American Transmission Systems, Incorporated

By: __________________________________
Name: Richard R. Grigg
Title: President
Date: December 17, 2009

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

City of Cleveland, Department of Public Utilities
Division of Cleveland Public Power

By: _ ________________________________
Name: Barry A. Withers
Title: Director
Date: March 22, 2011

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

Duke Energy Ohio, Inc.

By: _ ________________________________

Name: Julia S. Janson

Title: President

Date: September 27, 2011

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

Duke Energy Kentucky, Inc.

By: _ ________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

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

City of Hamilton, OH

By: ______________________________
Name: Joshua A. Smith
Title: City Manager
Date: February 29, 2012

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

Hudson Transmission Partners, L.L.C.

By: ___________________________________
Name: Jeffrey T. Wood
Title: Senior Vice President
Date: February 8, 2013

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

East Kentucky Power Cooperative, Inc.

By: _ ___________________________________
Name: Anthony S. Campbell
Title: President & CEO
Date: March 26, 2013

Section(s) of the PJM Service Agreements Tariff

(Clean Format)

PJM Service Agreement No. 3517

(Clean Format)

Service Agreement for

Network Integration Transmission Service

East Kentucky Power Cooperative, Inc.

June 1, 2013

ATTACHMENT F

Service Agreement For
Network Integration Transmission Service

1.0 This Service Agreement, dated as of *March 1, 2013*_____, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the Transmission Provider) as the administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and **East Kentucky Power Cooperative, Inc.** ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a valid request for Network Transmission Service under the Tariff and to have satisfied the conditions for service imposed by the Tariff.

3.0 Service under this agreement shall commence on the later of: (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

4.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Transmission Service in accordance with the provisions of the Tariff, including the Network Operating Agreement (which is incorporated herein by reference), and this Service Agreement as they may be amended from time to time.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider (on behalf of Transmission Provider and Counterparty):

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Transmission Customer:

East Kentucky Power Cooperative, Inc.

4775 Lexington Rd.

Winchester, KY 40392

6.0 The Tariff for Network Integration Transmission Service is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Office of the Interconnection:

By: _/s/ *Michael J. Kormos* Sr. V.P. - Operations __3/01/2013__
Name Michael J. Kormos Title Date

Counterparty:

By: */s/ Stanley H. Williams*__ _President_____ __3/01/2013___

Name Stanley H. Williams Title Date

Transmission Customer:

By: */s/ Don Mosier*__________ EVP & COO_____ ___3/01/2013___
Name Don Mosier Title Date

CERTIFICATION

I, *_/s/ Don Mosier_*_________, certify that I am a duly authorized officer of **East Kentucky Power Cooperative, Inc.** (Transmission Customer) and that **East Kentucky Power Cooperative, Inc.** (Transmission Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

_/s/ Don Mosier________________
(Name)

_EVP & COO_________________
(Title)

Subscribed and sworn before me this _*15th*__ day of __*March*______, _2013___.

*/s/ Brenda Bowers*___________________________
(Notary Public)

My Commission expires:__*1/24/17*_____________

SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE

l.0 Term of Transaction: 5 Years

Start Date: June 1, 2013

Termination Date: May 31, 2018

2.0 Description of capacity and/or energy to be transmitted within the PJM Region (including electric control area in which the transaction originates).

Capacity or energy, or both, from the PJM markets.

3.0 Network Resources:

N/A

4.0 Network Load:

Approximately 3,670 megawatts of load in the East Kentucky Power Cooperative, Inc. zone of the Transmission Provider's Control area.

5.0 Designation of party subject to reciprocal service obligation:

In accordance with section 6.0 of the applicable sections of the PJM Open Access Transmisstion Tariff ("Tariff").

6.0 Name(s) of any Intervening Systems providing transmission service:

N/A

7.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the tariff.)

7.1 Embedded Cost Transmission Charge:

As per the applicable sections and Attachment H of the Tariff.

7.2 Facilities Study Charge:

As per the applicable sections of the Tariff.

7.3 Direct Assignment Facilities Charge:

As per the applicable sections of the Tariff.

7.4 Ancillary Services Charge:

As per the applicable sections of the Tariff.

7.5 Other Supporting Facilities Charge:

As per the applicable sections of the Tariff.

PJM Service Agreement No. 3518

(Clean Format)

Service Agreement for

Louisville Gas and Electric Company/Kentucky Utilities Company

June 1, 2013

ATTACHMENT F

Service Agreement For
Network Integration Transmission Service

1.0 This Service Agreement, dated as of *March 28, 2013*, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the Transmission Provider) as the administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and **Louisville Gas and Electric Company /Kentucky Utilities Company (collectively "LGE/KU")** ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a valid request for Network Transmission Service under the Tariff and to have satisfied the conditions for service imposed by the Tariff.

3.0 Service under this agreement shall commence on the later of: (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties. On such effective service date of this agreement, the Network Integration Transmission Service Agreement between East Kentucky Power Cooperative and LGE/KU shall thereupon immediately terminate, without need for further action.

4.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Transmission Service in accordance with the provisions of the Tariff, including the Network Operating Agreement (which is incorporated herein by reference), and this Service Agreement as they may be amended from time to time, and that certain *Stipulation and Recommendation* (the "Stipulation") approved by the Kentucky Public Service Commission in an Order issued in case No. 2012-00169 dated December 20, 2012, a copy of which Stipulation is attached hereto and made a part hereof. In the event of a conflict between the terms and conditions of the Stipulation and the terms and conditions of the Tariff, the Network Operating Agreement or the Service Agreement, as all are referenced above, the terms and conditions of the Stipulation shall control.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider (on behalf of Transmission Provider and Counterparty):

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Transmission Customer:

Louisville Gas and Electric Company /Kentucky Utilities Company

220 W. Main Street, 7th Floor

Louisville, KY 40202

6.0 The Tariff for Network Integration Transmission Service is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Office of the Interconnection:

By:	*/s/ Michael J. Kormos*	*Sr. V.P - Operations*	*3/28/2013*
	Name Michael J. Kormos	Title	Date

Counterparty:

By:	*/s/ Stanley H. Williams*	*President*	*3/28/2013*
	Name Stanley H. Williams	Title	Date

Transmission Customer:

By:	*/s/ Paul W. Thompson*___	*Chief Operating Officer*	_*3/27/2013*_
	Name Paul W. Thompson	Title	Date

CERTIFICATION

I, *Paul W. Thompson*, certify that I am a duly authorized officer of **Louisville Gas and Electric Company / Kentucky Utilities Company** (Transmission Customer) and that **Louisville Gas and Electric Company / Kentucky Utilities Company** (Transmission Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

/s/ Paul W. Thompson
(Name)

Chief Operating Officer
(Title)

Subscribed and sworn before me this *27* day of *March*, *2013*.

/s/ Jennifer S. Mattingly
(Notary Public)

My Commission expires: *July 21, 2013*

SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE

1.0 Term of Transaction: **5 years**

Start Date: **June 1, 2013**

Termination Date: **May 31, 2018**

2.0 Description of capacity and/or energy to be transmitted within the geographic boundaries of the PJM Region (including electric control area in which the transaction originates).

Approximately 120 megawatts of capacity and energy from units located in the LGE/KU Control Area.

3.0 Network Resources:

N/A

4.0 Network Load:

Approximately 120 megawatts of LGE/KU load located within the geographic boundaries of the East Kentucky Power Cooperative ("EKPC") Balancing Area.

5.0 Designation of party subject to reciprocal service obligation:

Per section 6.0 of the PJM Open Access Transmission Tariff ("Tariff").

6.0 Name(s) of any Intervening Systems providing transmission service:

None

7.0 Service under this Agreement is subject to the terms and conditions in the Stipulation.

7.1 Embedded Cost Transmission Charge:
Based on the terms and conditions in the *Stipulation*, as approved by the Federal Energy Regulatory Commission ("FERC").

7.2 Facilities Study Charge:
Based on the terms and conditions in the *Stipulation*, as approved by FERC.

7.3 Direct Assignment Facilities Charge:
Based on the terms and conditions in the *Stipulation*, as approved by FERC.

7.4 Ancillary Services Charge:
Based on the terms and conditions in the *Stipulation*, as approved by FERC.

7.5 Other Supporting Facilities Charge:
Based on the terms and conditions in the *Stipulation*, as approved by FERC.

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation is entered into this 2nd day of November 2012 by and among Louisville Gas and Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); East Kentucky Power Cooperative, Inc. ("EKPC"); Office of the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG") and PJM Interconnection, L.L.C., ("PJM") in the proceeding involving the above parties, which are the subject of this Stipulation and Recommendation, as set forth below. (The Utilities, EKPC, AG and PJM are referred to collectively herein as the "Parties.")

W I T N E S S E T H:

WHEREAS, EKPC filed on May 3, 2012, with the Kentucky Public Service Commission ("Commission") its Application *In the Matter of: The Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, L.L.C.*, and the Commission has established Case No. 2012-00169;

WHEREAS, the Utilities, AG and PJM have been granted intervention by the Commission in this proceeding;

WHEREAS, informal conferences, attended in person or by teleconference by representatives of the Parties and Commission Staff took place on October 12, 19, and 26, 2012, at the offices of the Commission, during which a number of procedural and substantive issues were discussed, including terms and conditions related to the issues pending before the Commission in this proceeding that might be considered by all Parties to constitute reasonable means of addressing their concerns;

WHEREAS, the Parties desire to recommend to the Commission that it enter its Order setting the terms and conditions that the Parties believe are reasonable as stated herein;

WHEREAS, it is understood by all Parties that this agreement is a stipulation among the Parties concerning all matters at issue in these proceedings pursuant to 807 KAR 5:001, Section 4(6);

WHEREAS, the Parties have spent many hours to reach the stipulations and agreements that form the basis of this Stipulation and Recommendation;

WHEREAS, the Parties, who represent diverse interests and divergent viewpoints, agree that this Stipulation and Recommendation, viewed in its entirety, is a fair, just and reasonable resolution of all the issues in this proceeding; and

WHEREAS, the Parties recognize that this agreement constitutes only an agreement among, and a recommendation by, themselves, and that all issues in this proceeding remain open for consideration by the Commission at the formal hearing in this proceeding.

NOW, THEREFORE, in consideration of the premises and conditions set forth herein, the Parties hereby stipulate, agree, and recommend as follows:

ARTICLE I. Agreement to Support EKPC's Integration Into in PJM

Section 1.1 Subject to all of the commitments and conditions contained herein, all Parties agree to support EKPC's request to integrate into PJM.

ARTICLE II. Maintenance of the Utilities' Load Outside of the PJM Markets

Section 2.1. The load served by the Utilities utilizing EKPC's transmission system (the "the Utilities' Load") has been, and the Utilities desire that it continue to be, part of the Utilities' Balancing Authority ("BA") and not treated as being within the PJM markets by virtue of EKPC's integration into PJM. The Utilities and EKPC, in coordination and cooperation with each other and with PJM, and subject to approval by the Federal Energy Regulatory Commission ("FERC"), shall keep the Utilities' Load outside of PJM as set forth in this Section.

Section 2.1.1. The Utilities' Load shall be pseudo-tied between PJM and the Utilities, so that such load will be in the Utilities' BA. The Utilities, EKPC, and PJM shall cooperate in good faith to determine the specific metering and related equipment and protocols in order to implement the pseudo-tying of the Utilities' Load between PJM and the Utilities' BA. Except as otherwise agreed between PJM and EKPC, each party shall bear its own costs to implement such arrangements, and in no events shall Utilities be responsible for costs incurred by PJM.

Section 2.1.2. The Utilities shall pay for transmission service on the EKPC transmission system for deliveries to the Utilities' Load in accordance with the terms of the PJM Open-Access Transmission Tariff ("OATT"), i.e., the EKPC Transmission Pricing Zone rate, subject to all other provisions of this Article II. The Utilities will be billed by and shall make payments to PJM for such service. The Utilities understand and acknowledge that the EKPC zonal rate, and thus the rate payable by the Utilities, is subject to change in accordance with EKPC's rights under the PJM Tariff and applicable laws and regulations, but such changes shall not contravene any provision in this Article II and will be calculated based on EKPC's transmission revenue requirements using PJM-prescribed and FERC-approved rate calculation methodologies.

Section 2.1.3. Because the Utilities' Load will be in the Utilities' BA and not in the PJM markets, PJM shall not charge the Utilities with any other rates or charges that are assessed on load that is within the PJM Markets pursuant to the PJM tariff, including, but not limited to Regional Transmission Expansion Plan, locational marginal prices, congestion, and administrative costs. This provision applies only to charges for transmission service for the Utilities' Load and does not address costs that may develop in furtherance of possible future, unknown FERC policies or requirements.

Section 2.1.4. With respect to Ancillary Services Schedules 1 (Scheduling, System Control and Dispatch Service) and 2 (Reactive Supply and Voltage Control from Generation or

Other Sources Service), the Utilities will contract with EKPC to supply such services to the Utilities, who will purchase them based upon the terms and conditions as currently set forth in Schedules 1 and 2 of EKPC's current Open Access Transmission Tariff. EKPC reserves its right to modify the rates for Schedules 1 and 2, and thus the charges payable by the Utilities; however, any such change shall be based only on EKPC's costs and not PJM's costs.

Section 2.1.5. The objective of this Article is to insulate the Utilities' Load from the effects of EKPC's integration into PJM by maintaining arrangements comparable to those that existed prior to EKPC's integration into PJM. If the FERC does not approve all of the terms of this Stipulation and Recommendation that require FERC approval, EKPC shall not unilaterally pursue its integration efforts; rather, recognizing the importance of EKPC fully integrating into PJM on or before June 1, 2013, EKPC and the Utilities shall work with all good faith, best efforts, and reasonable speed to negotiate and achieve modified means by which EKPC may fully integrate into PJM on terms acceptable to the Parties, the Commission, and FERC. If the Parties cannot agree upon such means in a timely manner, each Party reserves its right to make such proposals to the Commission and FERC as it deems appropriate and to protest and contest proposals by the other Party.

Section 2.1.6. The Utilities, EKPC and PJM acknowledge and agree that the EKPC load served from the Utilities' transmission system ("EKPC Load") is within the PJM BA and will be treated as EKPC zonal load. EKPC shall pay for transmission service on the Utilities' transmission system for deliveries to the EKPC Load in accordance with the Utilities' OATT; however, the Utilities shall not charge or allocate to EKPC Load the cost of any transmission project outside the Utilities' service territory arising from regional transmission expansion or planning associated with the Utilities' involvement in the Southeastern Regional Transmission Planning ("SERTP") group, which is the Utilities' planned means of complying with FERC Order No. 1000 and related policies or requirements. This provision applies only to charges for transmission service for EKPC Load and does not address costs that may develop in furtherance of possible future, unknown FERC policies or requirements. In the event Utilities' involvement in the SERTP is not a successful means of complying with FERC Order No. 1000 and related policies or requirements, EKPC reserves the right to challenge the Utilities' subsequent means of complying with FERC Order No. 1000 and related policies or requirements to the extent such subsequent means of compliance would result in increased charges or rates being assessed to the EKPC Load within the PJM BA and treated as EKPC zonal load.

Section 2.2. Any intervention by the Utilities into EKPC's filings with FERC relating to EKPC's integration into PJM shall be in support of these filings with FERC and shall not contest these arrangements or otherwise be of an adversarial nature; however, the Utilities reserve the right to oppose EKPC or PJM concerning any issue(s) that have not arisen in this proceeding, as well as to contest any deviation from EKPC's planned integration into PJM according to the terms of EKPC's application in this proceeding as modified or conditioned by the terms of this Stipulation and Recommendation. For the purposes of this provision, the following issues shall be deemed to have arisen in this proceeding (in addition to those that have actually arisen in this proceeding):

1. EKPC's request to shorten time to be eligible to participate in the Reliability Pricing Model ("RPM") market from 5 years to 3 years;
2. Filing of PJM-EKPC Network Integration Transmission Service ("NITS") Agreement;
3. Transfer of existing EKPC OATT, Point-to-Point, and NITS service agreements and interconnection agreements to the PJM tariff;
4. EKPC revenue requirements (rate) filing and ancillary services filing;
5. Notice of cancellation of EKPC's current OATT; and
6. PJM tariff amendments necessary to reflect EKPC's integration (adding EKPC as a pricing zone, EKPC's rates).

Section 2.3. EKPC agrees to engage in a good faith review of any FERC proceeding filed by the Utilities, either individually or in concert with other utilities, seeking approval of the SERTP as the Utilities' means of complying with FERC Order No. 1000 and related policies or requirements. If, following such review, EKPC agrees with the filing, it will intervene to support the Utilities' application in that proceeding insofar as it is consistent with the provisions and intent of this Stipulation and Recommendation.

Section 2.4. Concerning load switching for maintenance and restoration purposes, the Utilities and EKPC will continue to address load switching on the same terms as exist today.

ARTICLE III. EKPC's Contingency Reserve Sharing Group ("CRSG") Participation

Section 3.1. EKPC and PJM agree to work with the Utilities and TVA to develop a plan for how EKPC can fulfill its obligations (currently 94 MW of reserves) as a member of the CRSG. The Utilities acknowledge that EKPC and PJM have begun this effort.

EKPC, the Utilities, and PJM agree to work with all good faith and best practices with TVA to complete the plan timely, with a target completion date of December 31, 2012.

Section 3.2. EKPC and PJM further commit to use all good faith and best practices to resolve all disputes or issues that arise with TVA or the Utilities concerning the CRSG.

Section 3.3. EKPC, PJM, and the Utilities agree that the continuation of the CRSG is contingent upon NERC Standards as they exist today. If NERC Standards change that adversely impact any member of the CRSG, then that party or parties may exercise their rights to withdraw under the current CRSG agreement.

Section 3.4. Immediately upon TVA's issuance of its notice of withdrawal from the CRSG, the provisions of this Article III shall cease to be of any effect, and any and all obligations between any of the Parties to this Stipulation and Recommendation created solely by this Article III shall immediately end.

ARTICLE IV. Transmission System Operations

Section 4.1. EKPC and PJM agree to maintain the current interconnection agreement with the Utilities. PJM agrees that the amended September 2011 interconnection agreement entered into between EKPC and the Utilities does not have to be terminated. PJM can file the interconnection agreement with FERC with a PJM Service Agreement on it as part of the integration. This will ensure continued effective coordination of the Utilities' and EKPC's systems.

Section 4.2. EKPC and the Utilities further agree to operate and coordinate their 69 kV systems according to operating guides, procedures, and practices, written and unwritten, that exist today and impact the Utilities. This provision shall not conflict with the provisions of Section 4.1.

Section 4.3. PJM agrees to recognize and honor flowgates the Utilities identify to their RC, TVA.

The Joint Reliability Coordination Agreement Among and Between Midwest Independent System Operator, Inc.("MISO"), PJM Interconnection, LLC, and Tennessee Valley Authority ("JRCA"), revised May 1, 2009, is in effect as between PJM and TVA. (MISO has withdrawn from the JRCA.) The JRCA addresses the process by which a transmission entity, like the Utilities, identifies flowgates to be included in the Congestion Management Process, the required testing to verify the impacts of the flowgates, the requirements for data exchange to ensure that the identified flowgates are included in models, and the methods by which congestion management is implemented in real time operations.

PJM is committed via the JRCA to recognize and honor flowgates that the Utilities identify to TVA, the Utilities' Reliability Coordinator, if those identified flowgates pass the required testing that is specified in the FERC-approved Congestion Management Process, which is an attachment to the JRCA.

ARTICLE V. PJM Network Integration Study

Section 5.1. PJM agrees to provide to the Utilities modeling information and results of analyses related to critical contingencies identified in network integration studies for EKPC. PJM and EKPC further agree to work with the Utilities in a cooperative way, using all good faith and best practices, to supply to the Utilities such input, modeling, and analytical data concerning the EKPC network integration study as the Utilities reasonably request to understand and analyze any potential impacts to their system that EKPC's full integration into PJM may cause. EKPC, PJM, and the Utilities agree to follow all applicable Critical Energy Infrastructure protocols in their data exchanges. PJM commits to work with the Utilities to ensure a thorough understanding of analyses performed and to discuss alternative measures to mitigate planning criteria violations identified.

ARTICLE VI. Kentucky Public Service Commission's Ongoing Jurisdiction

Section 6.1. The Commission shall retain jurisdiction following the transfer of control from EKPC to monitor and enforce these commitments.

Section 6.2. The Commission shall have jurisdiction over PJM for the limited purpose of enforcing PJM's commitments as set forth in this Stipulation and Recommendation to the extent not inconsistent with the jurisdiction of the FERC; however, the Commission shall have no authority to enforce any commitment of PJM that is subject to acceptance by FERC but which acceptance FERC denies.

ARTICLE VII. Miscellaneous Provisions

Section 7.1. Except as specifically stated otherwise in this Stipulation and Recommendation, the Parties agree that making this Stipulation and Recommendation shall not be deemed in any respect to constitute an admission by any Party hereto that any computation, formula, allegation, assertion, or contention made by any other Party in these proceedings is true or valid.

Section 7.2. The Parties agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and are consistent with the public interest for purposes of approving EKPC's full membership in PJM pursuant to KRS 278.218.

Section 7.3. The Parties agree that, following the execution of this Stipulation and Recommendation, the Parties shall cause the Stipulation and Recommendation to be filed with the Commission by November 2, 2012, together with a recommendation that the Commission enter its Order on or before December 31, 2012, implementing the terms and conditions herein.

Section 7.4. Each signatory waives all cross-examination of the other Parties' witnesses unless the Commission disapproves this Stipulation and Recommendation, and each signatory further stipulates and recommends that the application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record (subject to all pending Petitions for Confidential Treatment and all applicable Confidentiality Agreements) and approved as filed, except as modified by this Stipulation and Recommendation. The Parties stipulate that after the date of this Stipulation and Recommendation they will not otherwise contest EKPC's application in this proceeding, as modified by this Stipulation and Recommendation, during the hearing in this proceeding, and that they will refrain from cross-examination of all witnesses during the hearing, except insofar as such cross-examination supports the Stipulation and Recommendation or EKPC's application subject to the commitments and conditions of this Stipulation and Recommendation.

Section 7.5. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation and Recommendation be accepted and fully incorporated into any Order approving EKPC's application in this proceeding.

Section 7.6. If the Commission issues an Order adopting all of the terms and conditions recommended herein, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such Order.

Section 7.7. The Parties agree that if the Commission does not implement all of the terms recommended herein in its final Order in this proceeding, or if the Commission in its final Order in this proceeding adds or imposes additional conditions or burdens upon the proposed transfer of control or upon any or all of the Parties that are unacceptable to any or all of the Parties, then: (a) this Stipulation and Recommendation shall be void and withdrawn by the Parties from further consideration by the Commission and none of the Parties shall be bound by any of the provisions herein, provided that no Party is precluded from advocating any position contained in this Stipulation and Recommendation; and (b) neither the terms of this Stipulation and Recommendation nor any matters raised during the settlement negotiations shall be binding on any of the Parties to this Stipulation and Recommendation or be construed against any of the Parties.

Section 7.8. The Parties agree that this Stipulation and Recommendation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

Section 7.9. The Parties agree that this Stipulation and Recommendation shall inure to the benefit of, and be binding upon, the Parties, their successors and assigns.

Section 7.10. The Parties agree that this Stipulation and Recommendation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations, or agreements made prior hereto or contemporaneously herewith, shall be null and void, and shall be deemed to have been merged into this Stipulation and Recommendation.

Section 7.11. The Parties agree that, for the purpose of this Stipulation and Recommendation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation. The Parties further agree that the resolution proposed herein is in accordance with law, for a proper purpose, and is consistent with the public interest, all as contemplated by KRS 278.218.

Section 7.12. The Parties agree that neither the Stipulation and Recommendation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein. This Stipulation and Recommendation shall not have any precedential value in this or any other jurisdiction.

Section 7.13. The signatories hereto warrant that they have informed, advised, and consulted with the Parties they represent in this proceeding in regard to the contents and significance of this Stipulation and Recommendation, and based upon the foregoing are authorized to execute this Stipulation and Recommendation on behalf of the Parties they represent.

Section 7.14. The Parties agree that this Stipulation and Recommendation is a product of negotiation among all Parties, and that no provision of this Stipulation and Recommendation shall be strictly construed in favor of, or against, any Party.

Section 7.15. The Parties agree that this Stipulation and Recommendation may be executed in multiple counterparts.

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

East Kentucky Power Cooperative, Inc.

HAVE SEEN AND AGREED:

_*/s/ Mark David Goss*__________
Mark David Goss, Counsel

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE SEEN AND AGREED:

*/s/ Kendrick R. Riggs*________
Kendrick R. Riggs, Counsel
Allyson K. Sturgeon, Counsel

Office of the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention

HAVE SEEN AND AGREED:

*/s/ Jennifer B. Hans*___________________
Jennifer B. Hans, Assistant Attorney General

PJM Interconnection, L.L.C.

HAVE SEEN AND AGREED:

*/s/ Jason R. Bentley*___________________
Jason R. Bentley, Counsel

Gallatin Steel Company

HAVE SEEN AND HAVE NO OBJECTION:

*/s/ Michael L. Kurtz*______________________
Michael L. Kurtz, Counsel
Kurt Boehm, Counsel

Attachment C

Testimony of Ms. Ann Wood (Exh. EKP-1)
and
Mr. Daniel Cooper (Exh. EKP-2)
on behalf of East Kentucky Power Cooperative, Inc.

(Identified by Additional Cover Pages)

Testimony of Ms. Ann Wood
Exh. EKP-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C,	)	
East Kentucky Power Cooperative, Inc.	)	Docket No. ER13-___-000
	)	

DIRECT TESTIMONYOF ANN F. WOOD
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ann F. Wood. My business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by EKPC. I am Director of Regulatory Services.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE

A. I received a B.S. Degree in Accounting from Georgetown College. After graduation I accepted an audit position with Coopers & Lybrand in the Lexington office. My responsibilities ranged from performing detailed audit testing to managing audits. In October 1995, I started working for Lexmark International, Inc. as an analyst. In May 1997, I joined EKPC and held various management positions in the accounting, internal auditing, and regulatory services areas. In February 2011, I became Director of Regulatory Services at EKPC. I am a certified public accountant in Kentucky.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY ON UTILITY RATE OR COST MATTERS?

A. Yes. I have testified before the Kentucky Public Service Commission ("KPSC") on various matters including base rate proceedings, fuel adjustment clause proceedings and environmental surcharge proceedings.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of EKPC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the EKPC accounting process and the derivation of the cost information used by EKPC Witness Cooper in preparation of the formula transmission rates he is sponsoring. This accounting process and cost derivation will also be used by EKPC on a going-forward basis for the annual transmission rate updates and the true-up calculations described in the Formula Rate Protocols in Attachment H-24B (contained in Exhibit EKP-3) that Mr. Cooper is sponsoring.

Q. DOES EKPC FOLLOW THE UNIFORM SYSTEM OF ACCOUNTS IN ITS COST ACCOUNTING?

A. Yes. EKPC follows the Rural Utilities Service ("RUS") Uniform System of Accounts (7 CFR Part 1767). The RUS Uniform System of Accounts mirrors the FERC Uniform System of Accounts. EKPC's financial information is prepared using generally accepted accounting principles.

Q. IS EKPC REQUIRED TO FILE AN ANNUAL REPORT (FERC FORM 1) WITH THE COMMISSION?

A. No. While EKPC presently has a voluntary Open Access Transmission Tariff ("OATT") on file with the Commission, as an RUS-financed cooperative, EKPC is not a FERC-jurisdictional "public utility" under the provisions of Part II of the

Federal Power Act. Although not required by the FERC, EKPC does prepare an EKPC Form FF1 annually for submission to the Kentucky Public Service Commission ("KPSC").

Q. AS AN RUS BORROWER, IS EKPC REQUIRED TO FILE AN ANNUAL REPORT WITH THE RUS?

A. Yes. EKPC is required to file an annual RUS Form 12.

Q. WAS THE RUS FORM 12 THE SOURCE FOR THE COST DATA USED IN THE FORMULA RATE CALCULATION FOR THIS PROCEEDING?

A. No. The source for the cost data used in the formula rate calculation for this proceeding is the EKPC Form FF1. As explained above, EKPC is not required to file a FERC Form 1. However, each year EKPC does prepare an EKPC Form FF1 using the same format and requirements as would be used by a FERC-jurisdictional entity in preparing a Form 1 to be filed with the Commission. Consequently, EKPC sourced the information supporting this filing from EKPC Form FF1 versus the RUS Form 12 since the EKPC Form FF1 format was closer to the documents filed by FERC jurisdictional utilities.

Q. PLEASE EXPLAIN THE PROCESS USED TO PREPARE EKPC's FORM FF1.

A. The source of most information contained in the EKPC Form FF1 is EKPC's PeopleSoft accounting system. EKPC will submit its EKPC Form FF1 to the KPSC by April 1, 2013. The KPSC publishes this information on its website. However, it may be several days before the information appears on the KPSC website. The relevant pages from EKPC's Form FF1 are not available in a form that meets the Commission's electronic filing requirements as of the date of this filing. However, EKPC will post the EKPC Form FF1 to an FTP site that can be accessed by the Commission Staff. Staff may contact EKPC's counsel for instructions to access that site. Members of the public may obtain this same information by requesting a CD of the EKPC Form FF1. Anyone wishing to obtain the EKPC Form FF1 may contact EKPC's counsel for further instruction. In addition to the EKPC Form FF1 supporting information and calculations are included in the Appendices to H-24A, as provided in Exhibit EKP-3 to this filing.

Q. WITH REFERENCE TO THE FORMULA RATE WORKSHEET AND SUPPORTING PAGES ATTACHED TO THE FILING AS EXHIBIT EKP-3, PLEASE EXPLAIN THE MEANING OF THE "PG REF" NOTATIONS IN THE FOOTNOTES ON THIS PAGE AND ELSEWHERE IN THIS EXHIBIT?

A. The "PG REF" notations throughout Exhibit EKP-3 reflect the EKPC Form FF1 page (PG) reference (REF).

Q. THE SUPPORT PAGE ATTACHMENT H-24A, APPENDIX A, CONTAINS THE CALCULATION OF EKPC'S SCHEDULE 1A CHARGES. LINE 2 ON THIS PAGE HAS AN ENTRY FOR "REVENUE CREDITS FOR SCHEDULE 1A" THAT IS PRESENTLY BLANK. PLEASE DESCRIBE THIS ENTRY AND HOW EKPC WILL ADDRESS IT.

A. This item recognizes that EKPC will in the future receive an allocation of Schedule 1-related revenues that PJM collects for through and out service. As EKPC is not yet a transmission owning member of PJM, EKPC has not received any revenues for this item to date. At such time as EKPC begins receiving this allocation from PJM, EKPC will enter the amounts received under Account 457.1. The amounts in Account 457.1 will be applied as a credit against EKPC Schedule 1A costs for all True-ups and annual transmission rate updates subsequent to the time EKPC begins to receive that allocation.

Q. THE SUPPORT PAGE ATTACHMENT H-24A, APPENDIX D, CONTAINS THE DEPRECIATION RATES USED IN THE RATE CALCULATION. CAN YOU DESCRIBE THE REASON THOSE RATES WERE USED?

A. Yes. The depreciation rates used in the rate calculation (for the derivation of depreciation expense and accumulated depreciation) are the rates approved by the KPSC in Case No. 2006-00236. EKPC will not propose to modify the depreciation rates used as part of its annual formula rate calculation unless the depreciation rates have been approved in a proceeding before the KPSC and the Commission.

Q. THE SUPPORT PAGE ATTACHMENT H-24A, SUPPORT EXHIBIT PAGE 3 OF 8 CONTAINS THE INFORMATION ON ADVERTISING EXPENSES, AND REGULATORY EXPENSES. CAN YOU EXPLAIN THE DERIVATION OF THE ENTIRES ON THIS PAGE?

A. EKPC ran a query from its PeopleSoft accounting system to determine the specific components of advertising expense, recorded in account 930.1, that were not directly related to safety. These non-safety advertising items were removed from EKPC's transmission rate calculation. Additionally, Kentucky Revised Statute ("KRS") 278.130 covers assessments against utilities. Each year the Kentucky Department of Revenue assesses utilities subject to KPSC jurisdiction a charge based on the prior calendar year's intrastate revenues. This assessment is made for the purpose of maintaining the KPSC, including the payment of salaries and all other expenses, and the cost of regulation. EKPC has removed the assessments that are not specifically related to transmission, based on the wages and salaries allocator provided on Attachment H-24A, page 4 of 5, line 16.

Q. THE SUPPORT PAGE ATTACHMENT H-24A, SUPPORT EXHIBIT PAGE 3 OF 8 CONTAINS THE INFORMATION ON

PJM TRANSITION COSTS. CAN YOU EXPLAIN THE DERIVATION OF THE ENTIRES ON THIS PAGE?

A. EKPC has incurred certain costs associated with its integration into PJM. EKPC is amortizing those costs over a three-year period, which is consistent with the period over which rate case expenses are amortized in proceedings before the KPSC.

Q. THE SUPPORT PAGE ATTACHMENT H-24A, SUPPORT EXHIBIT PAGE 4 OF 8 CONTAINS THE INFORMATION ON BALANCING AUTHORITY COSTS. PLEASE DISCUSS THE ENTRIES ON THIS PAGE.

A. In calendar year 2012, EKPC was its own balancing authority. The Tennessee Valley Authority ("TVA") was EKPC's reliability coordinator. Pending FERC approval of EKPC's integration into PJM, EKPC will no longer need an external reliability coordinator. Consequently, those costs were removed from the 2012 cost data used in populating Attachment H-24A.

Q. THE SUPPORT PAGE ATTACHMENT H-24A, SUPPORT EXHIBIT, PAGE 5 OF 8 CONTAINS INFORMATION NECESSARY TO REMOVE PLANT INCLUDED IN TRANSMISSION THAT IS INCLUDED IN OATT ANCILLARY SERVICES. PLEASE DISCUSS THE ENTRIES ON THIS PAGE.

A. The costs of GSUs were sourced from EKPC's PeopleSoft Asset Management System. These costs are included in the total of account 353, reflected on Ref page 206 of the EKPC Form FF1.

Q. **THE SUPPORT PAGE ATTACHMENT H-24A, SUPPORT EXHIBIT, PAGE 6 OF 8 CONTAINS INFORMATION NECESSARY TO ADJUST FOR VARIOUS REVENUE CREDITS. PLEASE DISCUSS THE ENTRIES ON THIS PAGE.**

A. EKPC removed all revenue that is not associated with transmission-related revenue. Non-transmission-related revenue removed includes: revenue from steam sales, sales of renewable energy credits, and over or under recoveries related to various non-transmission related Kentucky-jurisdictional cost recovery mechanisms (Line 8); facility charges (Line 11); and sales tax compensation (Line 12). EKPC also removed the transmission revenue associated with its current firm and non-firm point-to-point and network integration service rate (Line 14) under the EKPC OATT because that OATT will be cancelled upon EKPC's integration into PJM. Line 16 represents the removal of revenues under a transmission agreement between AEP and EKPC, where those parties, with PJM concurrence and subject to Commission approval, have elected to leave the agreement in place. The pricing of transmission service for the AEP loads served over the EKPC transmission system will remain the same upon EKPC's integration into PJM.

Q. **THE SUPPORT PAGE ATTACHMENT H-24A, SUPPORT EXHIBIT, PAGE 7 OF 8 CONTAINS INFORMATION ON EKPC'S CAPITAL STRUCTURE, TIER VALUE, AND EFFECTIVE RATE FOR EKPC'S RATE CALCULATION. PLEASE DISCUSS THE ENTRIES ON THIS PAGE, ALONG WITH THE TIER VALUE.**

A. The interest expense and long-term debt amounts are sourced from EKPC's Form FF1 reference pages 117 and 112, respectively. EKPC's Proprietary Capital, also reflected on reference page 112, consists primarily of the following: memberships, patronage capital, and donated capital.

As an electric cooperative, EKPC uses a Times Interest Earned Ratio ("TIER") instead of the rate of return on equity that an investor-owned utility would use. TIER is calculated as follows:

$$TIER = \frac{net\ margins + interest\ on\ long\ term\ debt}{(interest\ expense\ on\ long\ term\ debt)}$$

EKPC proposes to use a 1.50 TIER, which is consistent with the TIER level approved in KPSC Case No. 2010-00167. Please note that on October 11, 2012, EKPC entered into an Indenture of Mortgage, Security Agreement and Financing Statement (Open-End Mortgage) with U.S. Bank National Association as Trustee. Under this financing vehicle, a Margins for Interest ("MFI") calculation is used versus TIER. The difference between MFI and TIER is that MFI considers interest expense on <u>secured</u> debt as part of both the numerator and denominator. Since a 1.50 TIER was used in the determination of EKPC's rates in its most recent base rate case before the KPSC, the use of this TIER level in the transmission rate calculation is consistent and appropriate.

Q. THE SUPPORT PAGE ATTACHMENT H-24A, SUPPORT EXHIBIT, PAGE 8 OF 8 CONTAINS INFORMATION ON EKPC'S SALES. PLEASE DISCUSS THE ENTRIES ON THIS PAGE.

A. The demand included on Attachment 24A, Support Exhibit, page 8 of 8 reflects the system peak demand (coincident peak) during a 60 minute clock hour for 2013. The January 2013 and February 2013 information is sourced from this hourly information from its MV 90 metering system. The March 2013 through December 2013 monthly information is sourced from EKPC's forecasted demand. Load data from the various companies included in this Exhibit is sourced from monthly invoices received from these companies.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Winchester, Kentucky) Docket No. ER13-___-000

AFFIDAVIT OF ANN F. WOOD

I, Ann F. Wood, being duly sworn, depose and say that the statements contained in the foregoing prepared testimony for the East Kentucky Power Cooperative, Inc., are correct to the best of my knowledge, information and belief.

Ann F. Wood
Ann F. Wood

Subscribed and sworn to me before this 21st day of March, 2013

Notary Public

My commission expires MY COMMISSION EXPIRES NOVEMBER 30, 2013 NOTARY ID #409352

____

NOTARIAL SEAL

Testimony of Mr. Daniel Cooper
Exh. EKP-2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C,	)	
East Kentucky Power Cooperative, Inc.	)	Docket No. ER13-___-000
	)	

DIRECT TESTIMONYOF DANIEL E. COOPER
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel E. Cooper. My business address is 9150 W. Howe Road, Eagle, MI 48822.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as a Consulting Engineer by the firm of Jennings, Strouss & Salmon, P.L.C. ("JSS"). I am registered as a Professional Engineer in the State of Michigan

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE

A. I earned a Bachelors of Science degree in Electrical Engineering from the Rose Hulman Institute of Technology in 1974, and earned a Masters of Business Administration from Indiana University in 1979. Following receipt of my B.S.E.E. degree, I was employed in the Electric Systems Planning Department of the Indianapolis Power & Light Company. I joined the consulting firm of R. W. Beck in 1980 and worked as a consultant to electric systems around the country through 1992. During my time at R. W. Beck I was mainly involved in assisting municipal and cooperative clients in the areas of power supply planning, power supply contracts and electric rates. The Michigan Public Power Agency (MPPA) was one of the clients I served while at R.W. Beck. MPPA recruited me in 1992, where I was employed through 2008, first as Engineering Manager and later as General Manager. While at MPPA I was responsible for development and administration of transmission and power supply agreements, member rates, and RTO matters. Thereafter I joined JSS as a non-lawyer consulting engineer.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the East Kentucky Power Cooperative, Inc. (EKPC).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the formula rate that EKPC proposes to use to calculate EKPC's transmission revenue requirements after EKPC integrates the operation of its generation and transmission assets into the PJM Interconnection, L.L.C. ("PJM"). This formula rate will be incorporated into the PJM Open Access Transmission Tariff ("OATT") to develop the transmission rates for the EKPC transmission pricing zone in PJM. I will also describe the other changes to the PJM OATT related to EKPC's revenue requirements that EKPC is proposing in connection with this integration.

Q. DOES EKPC HAVE WHOLESALE TRANSMISSION CUSTOMERS THAT WILL BE AFFECTED BY THE PROPOSED RATE?

A. Yes, although the number of entities affected is small. EKPC itself will be the most affected, as it purchases transmission service on behalf of its member distribution cooperatives. In addition, some loads of Duke Energy Ohio/Duke Energy Kentucky (DEOK), and some loads of Louisville Gas & Electric/Kentucky Utilities (LGE/KU) take wholesale transmission service from EKPC. These companies will be affected by the proposed EKPC transmission tariff and EKPC's proposed entry into PJM. I have also been informed that there is a reciprocal transmission arrangement between AEP and EKPC (the AEP-EKPC Agreement) concerning certain loads of each utility that are connected to and served over the other utility's system. I have been informed that EKPC intends to have the AEP-EKPC Agreement remain in place following EKPC's integration into PJM. If this is approved by the Commission, the AEP load connected to the EKPC system will remain subject to the terms of the AEP-EKPC Agreement and not be subject to the proposed EKPC wholesale transmission rate under the PJM OATT.

Q. IS EKPC PRESENTLY A MEMBER OF AN RTO OR ISO?

A. No, EKPC is not a member of any ISO or RTO at the present time.

Q. HAVE REGULATORS RESPONSIBLE FOR EKPC RATES TO ITS MEMBER COOPERATIVES BEEN INVOLVED CONCERNING EKPC's INTEGRATION INTO PJM?

A. Yes. I have been advised that Kentucky law requires that any utility that desires to sell, turn over control or control rights to another entity has to receive approval of the Kentucky Public Service Commission ("KPSC") to do so. EKPC made such a filing to seek KPSC approval to turn functional control of its transmission facilities over to PJM. The KPSC held an evidentiary hearing in KPSC Case No. 2012-00169. On December 20, 2012, the KPSC approved EKPC's transfer of functional control of its 100 kV+ transmission facilities to PJM, subject to certain conditions. These conditions pertain mainly to a stipulation between EKPC, PJM, the Kentucky Attorney General, and LGE/KU. The intent of the stipulation is to shield LGE/KU from PJM costs while allowing EKPC to recover part of its transmission-related ownership and operating costs from LGE/KU load served over EKPC's transmission system. That KPSC approval was included in an informational filing with the Commission - *INFORMATIONAL FILING OF EAST KENTUCKY POWER COOPERATIVE, INC.*, Docket No. RM10-23-000, filed December 27, 2012.

Q. DOES EKPC PRESENTLY HAVE A WHOLESALE TRANSMISSION RATE ON FILE WITH THE COMMISSION?

A. Yes. EKPC is not a "public utility" under the provisions of the Federal Power Act, but EKPC elected to filed a non-jurisdictional "Safe Harbor" OATT with the Commission in keeping with the reciprocity provisions of Order No. 888.

Q. ARE THE PROPOSED EKPC WHOLESALE TRANSMISSION RATES THE SAME AS THOSE EKPC PRESENTLY HAS ON FILE WITH THE COMMISSION?

A. No. The transmission rates included in EKPC's present OATT were developed based on historical data from calendar year 1996. EKPC's non-jurisdictional OATT will be cancelled upon EKPC's integration into PJM. In reviewing its rates in anticipation of EKPC's becoming a transmission pricing within PJM, EKPC's management determined that changes in EKPC transmission investment, costs and loads warranted updating those transmission rates. Further, EKPC's management concluded that a change from a static stated rate to an annually-updated "look ahead" formula rate would better serve the interests of EKPC, its member-customers, and users of the grid generally. EKPC's proposed adoption of a formula transmission rate is consistent with industry trends and Commission policy.

Q. WHAT RATES ARE EKPC PROPOSING TO MODIFY IN THIS FILING?

A. EKPC is proposing new transmission revenue requirements and the associated rates for:

(1) Network Integrated Transmission Service – PJM OATT Schedule H-24;

(2) Transmission Owner Scheduling, System Control and Dispatch Service – PJM OATT Schedule 1A;

(3) Short-term and long-term PTP transmission service – PJM OATT Schedule 7; and

(4) Non-firm point-to-point transmission service – PJM OATT Schedule 8.

Q. CAN YOU BRIEFLY DESCRIBE THE CHANGES FROM THE PRESENT TRANSMISSION RATE DEVELOPMENT TO THE RATE DEVELOPMENT YOU ARE PROPOSING?

A. EKPC is proposing two primary changes to EKPC's rate development. The first change is to conform EKPC's Network Integration Transmission Service ("NITS") rate to the rate determinants used in the PJM OATT. EKPC's present rate is applied to a NITS customer based on the customer's load at the time of the monthly EKPC transmission system peak. This is typically called a "12 CP" rate. PJM's OATT calls for a NITS customer's transmission charges to be based on the customer's load at the time of the annual zonal transmission peak. In this case, that means the NITS's customer's transmission billing will be applied against the customer's load in the clock hour in which the highest load on the EKPC transmission system in the year occurs. This is known as a "1 CP" rate. As a result, it is necessary to recalculate the EKPC zonal NITS rate using billing determinants that are consistent with recovery of revenue requirements under PJM's 1 CP NITS rate application.

The second change EKPC is proposing is in the development of EKPC's zonal transmission rates. The present EKPC wholesale transmission rates were developed on a static "stated rate" basis. The revenue requirements and loads used in calculating the rates were based on a historical test year. The rates remained fixed until modified by EKPC.

EKPC is proposing to change the approach used in developing EKPC's transmission rate calculation to a "look ahead" formula rate with an annual reconciliation and associated customer protocols. EKPC will use the approved formula approach with actual historical capital, expense and load data to prepare annual updates to the transmission rates that will be collected from transmission customers in the EKPC Zone by PJM under the PJM OATT.

Q. EXPLAIN WHAT YOU MEAN BY A LOOK-AHEAD FORMULA RATE WITH RECONCILIATION.

A. For the purposes of my testimony, I am defining a look-ahead formula rate with reconciliation as being a process where EKPC will develop an estimate of its transmission revenue requirements for the coming Rate Year using the then most recent calendar year's actual historical transmission cost and projected load data in a Commission-approved formula template. EKPC may make adjustments to the historical cost data used in developing the look-ahead transmission revenue requirements to include estimated cost impacts for new facilities expected to go into service in the coming year. The most likely such adjustment would be increases in capital and expenses resulting from new transmission plant planned to come on line during the coming Rate Year. EKPC will also use a combination of available actual transmission load information that is available for the year in which the rate update is being calculated, along with projected loads for the months in that same year where actual data is not yet available. EKPC will then use the estimated costs and projected loads to calculate the transmission rates that will be in effect for the EKPC Zone in the coming Rate Year. This is the look-ahead formula portion of the rate.

Following each calendar year, EKPC will prepare an annual "true-up" to calculate the difference between the actual transmission revenue collected in the preceding calendar year and the actual transmission revenue requirements for that preceding calendar year. The actual revenue requirements for the preceding year will be calculated using the Commission-approved formula rate template. EKPC will then calculate the difference between that actual transmission revenue requirement and the actual transmission revenues collected in that year. That difference, which could be positive or negative, will be carried forward as either a credit or charge, in the calculation of the transmission revenue requirement for the next Rate Year. That is the reconciliation portion of EKPC's proposed rate process.

In performing the above calculations, EKPC will follow its proposed customer protocols, included in Attachment H-24B to the PJM OATT, to enable stakeholder access to the information supporting EKPC's actual revenue requirements for the preceding year, the true-up calculation, and the estimated transmission revenue requirements for the coming year. The protocols will also provide interested parties with an opportunity to ask clarifying questions, seek additional information or, if they so elect, challenge costs included in EKPC's revenue requirements calculations. EKPC's proposed customer protocols do not provide for interested parties to challenge EKPC's formula rate itself.

Q. WHY DOES EKPC DESIRE TO MOVE TO A LOOK-AHEAD FORMULA RATE WITH RECONCILIATION?

A. The benefit of using a look-ahead formula rate with reconciliation is that it more closely matches the timing of actual revenue requirements and collections from customers. The longer the lag between the incurrence and recovery of transmission costs, the greater the likelihood that there will be a difference between the actual revenue requirements and the actual revenue collection. The more active the construction of new transmission plant and incurrence of related costs, the more severe the impact of such lags. Decreasing the lag-time sends more correct price signals to customers while minimizing financial strains on both EKPC and its transmission customers that could result from the under-collection or over-collection of revenue requirements that can occur under a static stated rate.

Q. WHY DOES A LOOK-AHEAD FORMULA RATE WITH RECONCILIATION MORE ACCURATELY MATCH REVENUE REQUIREMENTS AND REVENUE COLLECTIONS, WHEN COMPARED TO EKPC'S PRESENT TARIFF RATE?

A. A static stated rate based on an historical test year, such as EKPC's present OATT rates, is accurate for the costs and loads that occurred in the test year. As time goes on, the capital base will vary due to additions, upgrades and accumulated depreciation, while operating costs and loads vary. This results in a mismatch between the utility's actual revenue requirements and rate collections from its customers because, until changed, the rates remain fixed and based on the historical data that is no longer reflective of then current costs and loads. As conditions change from the test year conditions, the actual revenue requirements and the revenue collection from customers will diverge under a stated rate approach. Depending upon the amount of capital improvements, depreciation, and changes in operating costs and loads, the result can be either an under-collection or over-collection of revenues. This can only be corrected by calculating a new stated rate based on updated information and filing that new rate with the appropriate regulatory body. However, even with the calculation of new rates, any differences between historical revenue requirements and revenue collections will be incurred with no correction.

A look-ahead formula rate with reconciliation, on the other hand, makes annual rate updates that minimize differences between the revenue requirements underlying the rates and the revenue collection. The look-ahead formula rate reconciliation process also adjusts annually for under-or over-collections due to year-to-year variances in loads and unexpected changes in costs.

Q. CAN YOU EXPLAIN WHY EKPC IS PROPOSING TO USE A COMBINATION OF ACTUAL AND PROJECTED LOADS FOR ITS ANNUAL RATE UPDATE?

A. One of the more volatile factors affecting transmission revenue collections is weather-related variations in customer loads. This is especially true for rates collected on a 1CP basis. With 1 CP rates, a single instance of extreme weather can set the load that will be the basis for charges for that year. EKPC has historically been a winter-peaking utility, with its annual peak typically occurring in January. As a result, EKPC is proposing to use available actual loads for the year in which the rate update is calculated. For example, the rate development that is included with my testimony for the PJM Rate Year beginning June 1, 2013 uses actual EKPC transmission loads for January and February, 2013. Projected 2013 loads are used for the remaining months, in this case March – December, 2013. Using this approach, NITS billings will be based on actual loads for seven months of the PJM Rate Year that fall in the same year in which the rates are calculated. This should significantly reduce the effect of weather-driven variances in EKPC's NITS rate collections. That should in turn reduce revenue under-collections or over-collections that will need to be reconciled during the following Rate Year.

Q. PLEASE EXPLAIN HOW THE PROPOSED RATE MECHANISM WILL WORK.

A. There are several steps involved in the proposed rate mechanism's process. These steps are described in detail in the proposed Formula Rate Implementation Protocols that I am sponsoring as a part of my testimony and which, when approved by the Commission, will become Attachment H-24B to the PJM OATT. The proposed formula rate protocols are included under Exhibit EKP-3, along with the populated formula rate template, appendices and supporting exhibits for EKPC's proposed zonal rates for the coming Rate Year.

A general discussion of the steps included in EKPC's formula rate process appears in the following paragraphs:

- <u>Historical Data</u> – Following the closing of EKPC's accounting records and completion of the financial audit for the preceding calendar year, but no later than April 30, EKPC will enter its accounting results into a form that follows the layout and content of the FERC Annual Report ("FERC Form 1"). While EKPC is not a FERC-jurisdictional public utility, the report will follow Commission requirements and procedures for the preparation of a FERC Form 1 to prepare the report designated by EKPC as its Form FF1. The EKPC Form FF1, which contains most of the information contained in the FERC Form 1, will be the source of historical data EKPC will use for its formula rate calculations. This historical data will provide the basis for EKPC's estimate of its transmission revenue requirements for the coming Rate Year, as well as the reconciliation of actual revenue requirements and actual revenue collection for the preceding year.

- Calculation of Prior Year Actual Revenue Requirements – EKPC will use the information from the EKPC Form FF1 for the preceding year to populate the formula rate template. The result of this step is the calculation of EKPC's actual transmission revenue requirements for the preceding year.
- Calculation of Prior Year Reconciliation Amount – EKPC will use the prior year actual revenue requirements and actual transmission revenue as shown in the EKPC Form FF1 for the preceding year to calculate any under-recovery or over-recovery of its transmission revenue requirements in the preceding year. For EKPC's initial Rate Year, beginning June 1, 2013, there will be no reconciliation calculation. Further, any reconciliation amount calculated for use in the Rate Year beginning June 1, 2014 will be adjusted to recognize that reconciliation only applies for the months of June through December, 2013.
- Calculation of Transmission Rates for the Coming Rate Year – EKPC will use the same proposed formula rate template to calculate the transmission rate for the coming Rate Year as will be used to calculate the reconciliation amounts. EKPC has informed me that it generally intends to use the actual unadjusted account data from the EKPC Form FF1for the preceding calendar year to populate that template. EKPC may adjust the actual account values used in the template for any significant changes expected to be in effect in the coming Rate Year. The most likely significant change that would trigger such an adjustment would be new transmission plant expected to go into service during the coming Rate Year. Beginning with the Rate Year starting June 1, 2014, the True-up adjustment (i.e., credit or charge) from the prior year reconciliation will also be used as an input to the effective transmission rates for the coming Rate Year. Further, as I previously discussed in this testimony, EKPC will use a combination of actual load data for the then-current year and projected data for the remainder of the then-current year in calculating the rates for the coming Rate Year.

- Posting of Information and Notification of Stakeholders – No later than April 30 of each year, EKPC will post the populated formula transmission rate template for the coming test year on the PJM web site. EKPC will also post support data necessary to evaluate EKPC's rate calculation on the PJM website and EKPC's OASIS site. The posted support data will include a copy of the EKPC Form FF1 that was used as a source for the calculation of the true-up and forward-looking rate, along with supporting materials for data not directly available from the EKPC FF1. EKPC's postings will also include contact personnel and information for stakeholders and other interested parties to use in making inquiries concerning the rate calculation or supporting information.
- Informational Meeting and Presentation for Stakeholders – Closely following or concurrent with the posting of the annual rate update and supporting information each year, EKPC will post a notice of the time and place of an open meeting for interested parties to attend. The purpose of the meeting will be for EKPC to provide a presentation on the annual transmission rate update and transmission plans. Interested parties at the meeting will be able to ask questions concerning the rate and supporting information.
- Information Exchanges and Dispute Process – In addition to the material presented at the informational meeting, interested parties may provide written questions pertaining to the inputs and supporting materials for the annual update of the transmission rate. EKPC will make a good faith effort to answer those inquiries. Interested parties will also have a specified period after each posting of the annual transmission rate update materials to challenge inputs to the annual transmission rate update. Challenges may be directed at EKPC concerning items such as accounting treatments of items. The form of the formula rate template itself will not be subject to challenge in this process. EKPC's proposed formula rate mechanism also includes a dispute process to address any challenges that can not be amicably settled between EKPC and an interested party.
- Changes to Annual Informational Filings with the Commission – To the extent that any review of the annual update of the transmission rates leads to a correction

that will result in an adjustment to a prior year's rate update, EKPC will promptly notify the affected parties of the correction and its impact. The impact of the correction will be included, with interest, in EKPC's next annual transmission rate update that follows the notification of the correction.

Q. IS THE RATE MECHANISM EKPC IS PROPOSING ALREADY IN USE BY OTHER TRANSMISSION OWNERS?

A. Yes. Several other PJM transmission owners are using a formula approach to set their transmission rates. A formula approach is also standard for MISO transmission owners. In fact, many MISO transmission owners have moved to a look-ahead formula rate approach with reconciliation similar to that being proposed for EKPC. Some examples of the MISO Transmission Owners using a look-ahead formula rate include: American Transmission Company, LLC ("ATC")[1], International Transmission Company ("ITC")[2], Michigan Electric Transmission Company ("METC")[3], NSP[4], Southern Indiana Gas and Electric Company ("Vectren")[5], and GRE[6]. Many non-RTO transmission owners have also adopted formula transmission rates.

I used the formula rate template approved for Duke Energy's transmission rates in PJM as the starting point in developing a formula rate template for EKPC. Duke's formula rate template was based on the Attachment O that Duke Energy Ohio and Duke Energy Kentucky (collectively, DEOK) used in MISO before transferring to PJM. As a result, the proposed EKPC formula rate template is similar to MISO's Attachment O, as well as being similar to the formula rate template DEOK uses in PJM.

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1 See Am. Transmission Co., Letter Order, Docket No. ER05-1506-000 (Dec. 20, 2005).
2 See Int'l Transmission Co., 116 FERC ¶ 61,036 (2006) ("ITC").
3 See Mich. Elec. Transmission Co., 117 FERC ¶ 61,314 (2006), reh'g denied, 118 FERC ¶ 61,139 (2007) ("METC").
4 See Xcel Energy Servs., Inc., 121 FERC ¶ 61,284 (2007) ("Xcel"); Xcel Energy Servs. Inc., Letter Order, Docket No. ER07-1415-001 (May 1, 2008).
5 See S. Ind. Gas & Elec. Co., Letter Order, Docket No. ER09-180-000 (Dec. 19, 2008).
6 See Midwest Indep. Transmission Sys. Operator, Inc., Letter Order, Docket No. ER09-108-000 (Dec. 23, 2008) (Great River Energy Attachment O letter order on compliance).

Q. WHAT CHANGES ARE YOU PROPOSING FOR DEVELOPMENT OF EKPC'S TRANSMISSION RATE DEVELOPMENT FROM THAT USED BY DEOK?

A. There are several differences between the revenue requirements development I am proposing for EKPC and that used by DEOK. However, with the exception of the reconciliation provisions, those differences are the result of the differences in history and capital structure between EKPC and DEOK. The differences are:

- No provisions for obligations from prior RTO membership –because EKPC is not exiting another RTO in order to join PJM, EKPC has no legacy obligations from such membership.
- Capital Structure – As a generation and transmission cooperative chartered under the RUS, EKPC operates under a different capital structure than an investor-owned utility such as DEOK. The cost of capital component of the required return used in calculating EKPC's transmission revenue requirements is based on EKPC's existing long-term debt, EKPC's Proprietary Capital account value, and the Times Interest Earned Ratio ("TIER") approved by the Kentucky Public Service Commission under Case No. 2010-00167.
- Adjustments for off-system loads – Some of the transmission facilities of utilities other than EKPC are located in the geographic region served by the EKPC member distribution cooperatives. This has resulted in some of EKPC's native load being connected to transmission facilities owned by other utilities (LGE/KU, DEOK, and AEP). This has also resulted in some of the native load of those other utilities being connected to EKPC's transmission system. EKPC has informed me that they have historically planned for and generated energy to meet the needs of the EKPC loads connected to other systems through pseudo-tie arrangements. EKPC, with PJM's concurrence, plans to continue operating in that mode. EKPC's formula rate includes adjustments necessary to include those EKPC loads that are connected to other utilities as a part of EKPC's native load for EKPC's zonal rate calculations.

- Look-ahead and annual reconciliation - As I previously discussed in this testimony, EKPC is also proposing to use a look-ahead rate development with annual reconciliations to adjust for any differences between actual transmission revenue collections and actual transmission revenue costs.

Q. HAVE YOU INCLUDED A CALCULATION OF THE NEW REVENUE REQUIREMENT AND PROPOSED RATES FOR NITS AND PTP SERVICE IN THIS FILING?

A. Yes. I have attached a set of schedules from a populated formula rate template for EKPC using EKPC data for calendar year 2012. These schedules appear as a part of Exhibit EKP-3. I have also included a set of pages containing supporting information and calculations that are a part of the formula rate template. These pages also appear under Exhibit EKP-3.

Q. WHAT WAS THE SOURCE OF THE TIER VALUE YOU USED IN THE ATTACHED REVENUE REQUIREMENTS CALCULATION?

A. As I previously stated, I used the TIER value approved by the Kentucky Public Service Commission in Case No. 2010-000167. This proceeding and the TIER value are also discussed in the testimony of EKPC Witness Wood.

Q. WHAT WAS THE SOURCE FOR THE DEPRECIATION RATES YOU USED IN EKPC'S REVENUE REQUIREMENTS CALCULATION?

A. I used the transmission plant-related depreciation rates approved by the Kentucky Public Service Commission in Case No. 2006-00236. These same depreciation rates were accepted by the RUS pursuant to a letter dated December 21, 2006.

Q. IS EKPC PROPOSING THE ABILITY TO MODIFY ITS TIER OR DEPRECIATION RATES AS A PART OF ITS ANNUAL FORMULA RATE CALCULATIONS?

A. No. EKPC does not consider either the TIER or the depreciation rates to be a part of the values it can modify as a part of its normal annual formula rate updates. I have been informed by EKPC that EKPC is aware of the requirement to file with the Commission and gain approval for changes in these factors and will follow that procedure when it desires to modify either or both of them.

Q. HAVE YOU INCLUDED A CALCULATION OF THE NEW REVENUE REQUIREMENT AND PROPOSED RATES FOR NITS AND PTP SERVICE IN THIS FILING?

A. Yes. I have included series of schedules that represent EKPC's calculation of the NITS and PTP service revenue requirement and rate calculation, which will be identified as Attachment H-24A in PJM's OATT. The calculation of revenue requirements and the resulting rates included with this filing are calculated using EKPC audited calendar year 2012 data. As such, EKPC is proposing that beginning with the PJM Rate Year starting June 1, 2013, the rates will apply to transmission service in the EKPC Zone for both NITS customers and for PTP transmission service under Schedules 7 and 8 of the PJM OATT. The revenue requirements and rate calculations are included in Exhibit EKP-3. Additional work papers supporting the revenue requirements and rate calculations also are provided in Exhibit EKP-3.

Q. WILL PJM'S OATT INCLUDE THE RESULTS OF THE CHANGES TO SCHEDULES 7 AND 8 FOR EKPC'S TRANSMISSION ZONE?

A. Yes. EKPC's calculated PTP services rate for the EKPC Zone will appear as calculated under Attachment H-24A of the PJM OATT.

Q. HOW WILL EKPC'S REVENUE REQUIREMENTS FOR TRANSMISSION OWNER SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE BE CALCULATED UNDER EKPC's PROPOSAL?

A. EKPC's Schedule 1A costs will be calculated using the same inputs and approach as used for calculating EKPC's zonal transmission rates. Appendix A of Attachment H-24A contains the formula rate for calculating the charges for

Transmission Owner Scheduling, System Control, and Dispatch Service based on the cost of operating the EKPC control center. The eligible costs for recovery for this service are recorded in specific accounts under the RUS's Uniform System of Accounts ("USofA") (which follows the Commission's USofA). Generally, the revenue requirement for Schedule 1A is equal to the sum of selected USofA operating and maintenance ("O&M") accounts as represented in the EKPC Form FF1. Dividing these O&M accounts by energy transmitted (*i.e.*, MWhs) in the new "EKPC Zone" determines the rate. I have attached the form containing the calculation of EKPC's Schedule 1A charge as a part of Exhibit EKP-3. I will also note that EKPC's Schedule 1A rate will also be subject to an annual true-up. This true-up will be performed as a part of EKPC's annual transmission rate true-up.

Q. DOES SCHEDULE 1A HAVE ANY EFFECT ON THE EKPC ZONAL NITS AND PTP SERVICE REVENUE REQUIREMENT CALCULATION?

A. No. The costs being recovered under PJM's Schedule 1A are all excluded from EKPC's NITS and PTP revenue requirements calculation and, therefore, have no bearing on the transmission charges calculated using the proposed formula rate calculation as shown in Attachment H-24A.

Q. HOW ARE REVENUES UNDER SCHEDULE 1A FROM NON-ZONAL CUSTOMERS TREATED?

A. PJM distributes non-zonal Schedule 1 revenue to PJM Transmission Owners based on allocations developed in stakeholder processes. Revenue recovered for Transmission Owner Scheduling, System Control, and Dispatch Service from non-zonal customers is distributed according to the established allocations. Any such revenue received by EKPC will reduce the amount recovered from EKPC zonal customers under Schedule 1A. This revenue credit is reflected in Attachment H-24A, Appendix A, line 2. Until PJM establishes the percentage of non-zonal Schedule 1A revenue allocable to EKPC, this credit is set at $0. Once PJM revises its schedule of allocations for Schedule 1A non-zonal revenue to reflect EKPC's membership in PJM, EKPC will reflect any such revenues received from PJM as a credit on Attachment H-24A, Appendix A, line 2.

Q. DOES EKPC'S FORMULA RATE ADDRESS HOW EKPC WILL BE COMPENSATED FOR ANY PJM REGIONAL TRANSMISSION ENHANCEMENT PROJECTS FOR WHICH EKPC IS RESPONSIBLE?

A. Yes. Should EKPC be assigned responsibility for constructing part or all of any regional transmission enhancement plan (RTEP) projects by PJM, EKPC will be entitled to recover the costs of such projects from customers outside the EKPC Zone under Schedule 12 of PJM's OATT. The revenue requirements for such projects will be developed pursuant to a formula included as Appendix B to Attachment H-24. The revenue requirements calculated in Appendix B will be provided to PJM for billing and PJM will, in turn, credit EKPC for its transmission enhancement projects revenue requirements.

To the extent rate base costs and operating expenses associated with EKPC-constructed transmission expansion projects are included in the overall EKPC NITS and PTP revenue requirements calculation, the revenue EKPC receives for such projects will be credited against the overall NITS and PTP revenue requirement calculation for EKPC zonal transmission rates.

Q. PLEASE PROVIDE A SUMMARY OF THE PROCESS OUTLINED IN APPENDIX B.

A. The formula shown in Appendix B is a standard revenue requirements calculation. The formula uses input data associated with the RTEP projects including gross plant, O&M expense, taxes other than income taxes, and a return (TIER) component.

Q. IS EKPC INCLUDING ANY REGIONAL PJM TRANSMISSION ENHANCEMENT CREDITS IN THIS INITIAL FILING?

A. No. This credit will only be for projects constructed by EKPC and approved by PJM under its RTEP process. Inasmuch as EKPC is not yet a member of PJM, there are no projects to include in this calculation at this time. Consequently, for the initial rates, the value of this adjustment is $0.

Q. HAS EKPC PREPARED A SET OF PROTOCOLS TO ACCOMPANY THE CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS UNDER THE PROPOSED FORMULA RATE?

A. Yes. EKPC's filing includes the proposed Attachment H-24B, which contains a detailed set of protocols describing the process to be used by EKPC in calculating and reconciling the formula rates for NITS, PTP, and Transmission Owner Scheduling, System Control, and Dispatch Service under Schedule 1A. The protocols being proposed are similar to protocols approved by the Commission for other PJM Transmission Owners. These formula rate protocols generally describe the methodology for the annual updates that will be made to the formula rates. Additionally, the protocols describe how the annual update will be posted and made available to customers, how customers can review the filings, how information requests will be handled, and how informal dispute resolutions regarding the annual update will be addressed. The proposed formula rate protocols are attached to my testimony as part of Exhibit EKP-3.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE PROPOSED RATE PROTOCOLS.

A. The protocols generally provide a discussion of the process the Companies will use to annually update its rates under Attachment H-24. EKPC will post and file with the KPSC and PJM by April 30th of each year all of the schedules, calculations, and assumptions used to support the annual reconciliation and revenue requirement calculation in Attachment H-24A. All of this information will be posted on PJM's website. Any interested party will have up to one hundred twenty (120) days after the date of publication to provide additional data requests to EKPC, and have up to one hundred fifty (150) days after the date of publication to review the material and to notify EKPC of any specific issues it seeks to challenge in the annual update filing. The protocols also contain a dispute resolution process that includes the opportunity to pursue disputes at the Commission.

Q. WILL YOU SUMMARIZE THE TARIFF CHANGES YOU ARE SPONSORING?

A. Yes. I am sponsoring EKPC's changes to Schedules 1A, 7, and 8, which add references to EKPC's formula rates. In addition, I am sponsoring EKPC's proposed Attachment H-24, which includes the following:

a. **<u>Attachment H-24</u>**: This is a brief statement covering the obligation of transmission customers in the EKPC Zone to pay for transmission service under rates shown in Attachment H-24A, along with other charges as applicable.

b. **<u>Attachment H-24A</u>**: Provides the detailed calculations and supporting data to calculate the NITS and PTP rates. References to source data are included. In addition to the formula rate, Attachment H-24A includes five appendices, as follows:

   i. **<u>Appendix A</u>**: Provides the detailed calculations and supporting data to calculate EKPC's Schedule 1A rate.

   ii. **<u>Appendix B</u>**: Provides the detailed calculations and supporting data to calculate the net RTEP transmission enhancement credit included in Attachment H-24A that will be used at such time as EKPC is responsible for transmission that is part of PJM's RTEP.

   iii. **<u>Appendix C</u>**: Shows the calculation of true-up reconciliations for EKPC's transmission revenue requirements and Schedule 1A charges based on any variance between actual revenue requirements and revenues collected in the preceding calendar year.

   iv. **<u>Appendix D</u>**: Shows the depreciation rates used by EKPC in the Attachment H--24A revenue requirements calculations.

v. **Supporting Exhibits**: Contains eight (8) pages containing supporting detail on capital accounts, expenses and load values used in developing the formula rate.

c. **Attachment H--24B**: Contains EKPC's Formula Rate Implementation Protocols.

Q. WHEN IS EKPC PROPOSING TO IMPLEMENT THE NEW RATES BEING PROPOSED IN THIS FILING?

A. EKPC requests the new rates be made effective on June 1, 2013, which is the proposed date for EKPC's joining PJM as a Transmission Owning member.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Lansing, Michigan) Docket No. ER13-___-000

AFFIDAVIT OF DANIEL E. COOPER, P.E..

I, Daniel E. Cooper, being duly sworn, depose and say that the statements contained in the foregoing prepared testimony for the East Kentucky Power Cooperative, Inc., are correct to the best of my knowledge, information and belief.

Daniel E. Cooper, P.E.

Subscribed and sworn to me before this 27th day of March, 2013

Notary Public

My commission expires Oct. 20, 2017

NOTARIAL SEAL

SUSAN L. MONTALVO
NOTARY PUBLIC - STATE OF MICHIGAN
COUNTY OF EATON
My Commission Expires Oct. 20, 2017
Acting in the County of Eaton

4352081v1(56627.5)

Attachment D

Populated Formula Rate (Exh. EKP-3)

Formula Rate - Non-Levelized | For the 12 months ended 12/31/2012

Rate Formula Template
Utilizing EKPC 2012 Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 60,283,814
	REVENUE CREDITS	Note A	Total	Allocator		
2	Account No. 454	(page 4, line 34)	$112,335	TP	1.00000	$ 112,335
3	Account No. 456.1 (Net of Revenues from Grandfathered Transactions)	(page 4, line 35)	142,658	TP	0.97346	138,871
4	Revenues from Grandfathered Transactions	Note B	159,632	TP	0.97346	155,395
5	Revenues from service provided by the ISO at a discount		0	TP	0.97346	0
5a	Transmission Enhancement Credit		0	TP	0.97346	0
6	TOTAL REVENUE CREDITS (sum lines 2-5b)					$ 406,601
6a	True-up Adjustment	Note C				$ -
7	NET REVENUE REQUIREMENT	(line 1 minus line 6 plus line 6a)				$ 59,877,213
	DIVISOR					
8	1 CP	Note D				2,990,884
9	12 CP	Note E				2,440,711
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$20.020			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$24.533			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$1.668			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$2.044			
			On-Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.472			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.094	Capped at weekly rate		$0.067
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$5.897	Capped at weekly and daily rate		$2.801

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2012

Rate Formula Template
Utilizing EKPC 2012 Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.	(1) RATE BASE	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	204.46.g	$2,856,825,691	NA		
2	Transmission	206.58.g	545,126,929	TP	0.97346	$530,658,909
3	Distribution	206.75.g	184,895,038	NA		
4	General & Intangible	204.5.g & 206.90.g	102,061,486	W/S	0.13574	13,853,916
5	Common		0	CE	0.00000	0
6	TOTAL GROSS PLANT(sum lines1-5)		$3,688,909,144	GP=	14.761%	$544,512,825
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$784,290,804	NA		
8	Transmission	219.25.c	149,994,218	TP	0.97346	$146,013,275
9	Distribution	219.26.c	48,265,455	NA		
10	General & Intangible	219.28.c	67,427,280	W/S	0.13574	9,152,638
11	Common		0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$1,049,977,757			$155,165,913
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$2,072,534,887			
14	Transmission	(line 2 - line 8)	395,132,711			$384,645,634
15	Distribution	(line 3 - line 9)	136,629,583			
16	General & Intangible	(line 4 - line 10)	34,634,206			4,701,278
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		$2,638,931,387	NP=	14.754%	$389,346,912
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	272.Total 281.k	$ -	NA	zero	$ -
20	Account No. 282 (enter negative)	274.Total 282.k	0	NP	0.14754	0
21	Account No. 283 (enter negative)	276.Total 283.k	0	NP	0.14754	0
22	Account No. 190	234.Total 190.c	0	NP	0.14754	0
23	Account No. 255 (enter negative)	266.Total.h	0	NP	0.14754	0
24	TOTAL ADJUSTMENTS (sum lines 19-23)		$ -			$ -
25	LAND HELD FOR FUTURE USE	214.Total.d, Note F	$ -		1.00000	$ -
	WORKING CAPITAL					
26	CWC	calculated, Note G	$7,218,188			3,204,646
27	Materials & Supplies	227.8.c	13,399,855	TE	0.91401	12,247,557
28	Prepayments (Account 165)	110.46.c, Note G	3,428,432	GP	0.14761	506,064
29	TOTAL WORKING CAPITAL (sum lines 26-28)		$24,046,475			$15,958,267
30	RATE BASE (sum lines 18, 24, 25, & 29)		$2,662,977,862			$405,305,179

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2012

Rate Formula Template
Utilizing EKPC 2012 Form FF1 Data
East Kentucky Power Cooperative, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.100	$39,136,936	TE	0.91401	$35,771,422
2	Less Account 565	321.Acct 565	17,209,056	TE	0.91401	15,729,193
3	A&G	321.168	37,010,077	W/S	0.13574	5,023,780
4	Less FERC Annual Fees	N/A	0	W/S	0.13574	0
5	Less Non-safety Advertising	Note H	334,597	W/S	0.13574	45,418
5a	Less KPSC Regulatory Expenses	Note H	1,491,840			
5b	Plus Transmission Related Regulatory Exp	Note H	202,504	TE	0.91401	185,090
5c	Plus Prorated PJM Transition Expense	Note H	431,483			431,483
6	Common		0	CE	0.00000	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6,7 less lines 1a, 2, 4, 5)		$57,745,507			$25,637,164
	DEPRECIATION EXPENSE					
9	Transmission	336.7.f	$8,530,083	TP	0.97346	$8,303,689
10	General and Intangible	336.9.f	7,733,862	W/S	0.13574	1,049,801
11	Common	336.10.f	0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9-11)		$16,263,945			$9,353,490
	TAXES OTHER THAN INCOME TAXES					
	LABOR RELATED					
13	Payroll	Note I	$ -	W/S	0.13574	$ -
14	Highway and vehicle	Note I	0	W/S	0.13574	0
15	PLANT RELATED					
16	Property	Note I	0	GP	0.14761	0
17	Gross Receipts		0	NA	NA	0
18	Other		0	GP	0.14761	0
19	Payments in lieu of taxes		0	GP	0.14761	0
20	TOTAL OTHER TAXES (sum lines 13-19)		$ -			$ -
	INCOME TAXES	Note J				
21	T=1 - {[(1-SIT) * (1-FIT)] / (1 - SIT * FIT * p)} =		0.000000%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.000000%			
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	0			
25	Income Tax Calculation (line 22 * line 28)		$ -	NA		$ -
26	ITC adjustment (line 23 * line 24)		0	NP	0.14754	0
27	Total Income Taxes	(line 25 plus line 26)	$ -			$ -
28	RETURN					
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 29)]		$166,183,724	NA		$25,293,160
29	REVENUE REQUIREMENT (sum lines 8,12, 20, 27, 28)		$240,193,175			$60,283,814

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EKPC 2012 Form FF1 Data
East Kentucky Power Cooperative, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.	Description	Reference	$	TP / %	Allocation / Cost		Amount
	TRANSMISSION PLANT INCLUDED IN ISO RATES						
1	Total transmission plant (page 2, line 2, column 3)						545,126,929
2	Less transmission plant excluded from ISO rates						0
3	Less transmission plant included in OATT Ancillary Services	See Supporting Exhibit, Page 5 of 8, Line 4, (Note K)					14,468,020
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)						530,658,909
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	0.97346
	TRANSMISSION EXPENSES						
6	Total transmission expenses (page 3, line 1, column 3)						39,136,936
7	Less transmission expenses included in OATT Ancillary Services	Note L					2,390,233
8	Included transmission expenses (line 6 less line 7)						36,746,704
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.93893
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.97346
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.91401
	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP	Allocation		
12	Production	354.18.b	31,951,523	0.00	0		
13	Transmission	354.19.b	6,989,147	0.97	6,803,651		
14	Distribution	354.20.b	748,864	0.00	0		W&S Allocator
15	Other	354.21,22,23,24.b	10,432,807	0.00	0		($ / Allocation)
16	Total (sum lines 12-15)		50,122,341		6,803,651	=	0.13574
	COMMON PLANT ALLOCATOR (CE)		%		% Electric		W&S Allocator
17	Electric	200.3.c	1.00		(line 17 / line 20)		(line 16)
18	Gas	201.3.d	0.00		1.00000	*	0.13574
19	Water	201.3.e	0.00				
20	Total (sum lines 17 - 19)		1.00				
	RETURN (R)						$
21		Long Term Interest (117, sum of 58.c through 65.c)					114,128,388
22		Preferred Dividends (118.29c) (positive number)					0
	Development of Cost of Capital:						
23	Long Term Debt	(112.23c) See Supporting Exhibit, Page 7 of 8					$2,743,241,312
24	Proprietary Capital	(112.15.c)					360,946,072
25	Less Account 216.1	(112.12.c) (enter negative)					0
26		Total Capital	(sum lines 23-25)				$3,104,187,384
			$	%	Cost		Weighted
27	Long Term Debt (112.23c)	Note M	2,743,241,312	88.37%	4.160%		3.677%
28	Proprietary Capital (112.15.c)	Note N	360,946,072	11.63%	**22.050%**		2.564%
29	Total (sum lines 27-28)		3,104,187,384		**R =**		**6.241%**
30	Effective TIER	Note O			**TIER =**		**1.50**
	REVENUE CREDITS						
	ACCOUNT 447 (BUNDLED SALES FOR RESALE)		(310-311)				
31	a. Bundled Non-RQ Sales for Resale (311.x.k)						$ -
32	b. Bundled Sales for Resale included in Divisor on page 1						0
33	Total of (a)-(b)						$0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	See Supporting Exhibit, Page 6 of 8, Line 3 (Note P)					$ 112,335
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)	See Supporting Exhibit, Page 6 of 8, Line 17 (Note Q)					$ 142,658

Rate Formula Template
Utilizing EKPC 2012 Form FF1 Data
East Kentucky Power Cooperative, Inc.

General Note: **References to pages in this formulary rate are indicated as: (page#, line#, col.#)**
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note
Letter

A The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Formulary Rate Template.

B Revenue from AEP Grandfathered Agreement. See Rev Cred Support, Attachment H-24A, Supporting Exhibit, page 6 of 8, line 16

C Calculated in accordance with the EKPC Formulary Rate Protocols in Attachment H-24B of this Tariff. See Appendix C

D EKPC 1 CP is EKPC's highest Monthly Firm Transmission System Peak Load based on the source data as described in Note 1 of Attachment H-24A, Page 8 of 8, plus transmission service provided for others over the EKPC transmission system, plus wheel-out to EKPC load connected to AEP/KP, Duke Ky, and LGE/KU
See Attachment H-24A, Supporting Exhibit, Page 8 of 8

E EKPC 12 CP is EKPC's Monthly Firm Transmission System Peak Load based on the source data as described in Note 1 of Attachment H-24A, Page 8 of 8, plus transmission service provided for others over the EKPC transmission system, plus wheel-out to EKPC load connected to AEP/KP, Duke Ky, and LGE/KU
See Attachment H-24A, Supporting Exhibit, Page 8 of 8

F Identified in EKPC Form FF1 as being non-transmission related. See Attachment H-24A, Supporting Exhibit, Pg 2 of 8

G Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3 of 5, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on EKPC Form FF1, Ref Pg 110, line 46.

H Line 5 - Remove non-safety related advertising included in Account 930.1. See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 3

Line 5a - Remove Total Regulatory Commission Expenses - See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 4
Line 5b - Add Back Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting - See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 6
Line 5c - Add EKPC costs relating to PJM transition. See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 14

I In accordance with RUS accounting standards, EKPC allocates all payroll and property taxes to the functional account. Labor- and plant-related taxes are already included in the appropriate transmission account.

J As a member-owned non-profit RUS generation and transmission cooperative, EKPC is exempt from state and from federal income taxes under 501(c)(12) of Internal Revenue Code

K Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, included in Account 561. See Attachment H-24A, Supporting Exhibit, Page 4 of 8.

M Debt cost rate = long-term interest (line 21) / long term debt (line 27).

N Proprietary Capital Cost calculated to achieve TIER of 1.50

O TIER value approved by KPSC in Case No. 2010-000167

P Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

Q Net of retained legacy transactions. See Attachment H-24A, Supporting Exhibit, page 6 of 8.

East Kentucky Power Cooperative, Inc.
Transmission Formula Rate Revenue Requirement
Utilizing EKPC 2012 Form FF1 Data
For Rates Effective January 1, 2012

Schedule 1A Rate Calculation

	Line No.		Source		Revenue Requirement	
A.		Schedule 1A Annual Revenue Requirements				
	1	Total Load Dispatch & Scheduling (Account 561)	Supporting Exh, page 4 of 8, line 11	$	2,390,233	
		Less allocated amount for steam production [(Line 6c/Line 6b) * Line 1]		$	47,058	
		Total Load Dispatch & Scheduling (Account 561) excluding Steam		$	2,343,175	
	2	Revenue Credits for Schedule 1A	Note 1	$	-	
	3	Net Schedule 1A Revenue Requirement for Zone		$	2,343,175	
	4	Less: True Up Under/(Over) Recovery for 12 months ended 12/31/2012	Note 2	$	-	
	5	Schedule 1A Recovery Amount for 12 Months ended		$	2,343,175	
B.		Schedule 1A Rate Calculations	Note 3			
	6	2012 Requirements Sales for Resale	Note 4		12,174,586	MWh
	6a	Plus Non-requirements Sales for Resale	Note 5		223,609	
	6b	Subtotal	Note 6		12,398,195	
	6c	Less Equivalent Steam			244,089	
	6d	Net MWh			12,154,106	MWh
	7	Schedule 1A rate $/MWh (Line 5 / Line 6)	(Line 3 / Line 6)		$0.1928	$/MWh

Notes:

(1) Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of EKPC's zone during the year used to calculate rates under Attachment H-24A
(2) Amount from Attachment H-24A, Appendix C, line 13 for stated year.
(3) Sourced from EKPC Form FF1, Ref Pg 401, adjusted for equivalent steam sold
(4) FF1, Ref Page 401, Line 23
(5) FF1, Ref Page 401, Line 24
(6) FF1, Ref Page 401, Footnote

Rate Formula Template
Utilizing Attachment Attachment H-24A
East Kentucky Power Cooperative, Inc.
RTEP - Transmission Enhancement Charges
To be completed in conjunction with Attachment H-24A

Line No.	(1)	(2) Attachment H-24A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Attachment H-24A, p 2, line 2 col 5 (Note A)	530,658,909	
2	Net Transmission Plant - Total	Attachment H-24A, p 2, line 14 col 5 (Note B)	384,645,634	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attachment H-24A, p 3, line 8 col 5	25,637,164	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	4.83%	4.83%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attachment H-24A, p 3, lines 10 & 11, col 5 (Note H)	1,049,801	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.20%	0.20%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attachment H-24A, p 3, line 20 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.00%	0.00%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**5.03%**
	INCOME TAXES			
10	Total Income Taxes	Attachment H-24A, p 3, line 27 col 5	-	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	0.00%	0.00%
	RETURN			
12	Return on Rate Base	Attachment H-24A, p 3, line 28 col 5	25,293,160	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	6.58%	6.58%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**6.58%**

Note

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-24A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-24A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-24A page 3 line 12.

F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G The Network Upgrade Charge is the value to be used in PJM OATT Schedule 26.

H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in Attachment H-24A Appendix B, page 2, column 9.

For the 12 months ended 12/31/2012

East Kentucky Power Cooperative, Inc.
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**Network Upgrade Charge**
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	5.03%	$0.00	$ -	6.58%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	5.03%	$0.00	$ -	6.58%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	5.03%	$0.00	$ -	6.58%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-24A, Page 1, Line 5c											$0

Note Letter

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-24A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-24A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-24A page 3 line 12.

F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G The Network Upgrade Charge is the value to be used in Schedule 26.

H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Rate Formula Template
Utilizing Attachment H-24A

East Kentucky Power Cooperative, Inc.
Calculation of Prior Year Transmission Revenue Requirement True-up Adjustment
To be completed in conjunction with Attachment H-24A

Line No.	(1)		(2)	
	Reconciliation Adjustment for Transmission Revenue Requirements			
1	Actual Transmission Revenue Requirement for 12 Months Ended 12/31/2012 including True Up for 12 months ended 12/31/2011 (1)		$	-
2	Less: True Up Under/(Over) Recovery Adjustment for EKPC Appendix H-24A for 12 months ended 12/31/2011 (2)		$	-
3	Transmission revenue requirements for the 12 months ended12/31/2012	(Line 1 - Line 2)	$	-
4	Less: Actual Transmission Revenue Collected for 12 months Ended 12/31/2012 (3)		$	-
5	True-Up Principal Under(Over) Recovery before Interest	(Line 3 - Line 4)	$	-
6	Monthly Interest Rate--Final FERC rate (4)			0.270%
7	Number of Months being Trued Up			12
8	Interest	(Line 5 x Line 6 x Line 7)	$	-
9	True Up Principal & Interest Under(Over) Recovery--Preliminary (5)	(Line 9 + Line 15)	$	-

Notes:
(1) Revenue requirement from Page 1 of 5, line 7 of Attachment H-24A for the referenced year.
(2) EKPC Attachment H-24A, page 1 of 5, Line 6a for the referenced recovery year
(3) Revenue received under PJM Tariff Schedules 7 and 8 under Attachment H-24A for the referenced year.
(4) See: ***http://www.ferc.gov/legal/acct-matts/interest-rates.asp*** for the appropriate Month
(5) Goes to Attachment H-24A , page 1 of 5, line 6a

Rate Formula Template
Utilizing Attachment H-24A

East Kentucky Power Cooperative, Inc.
Calculation of Prior Year Transmission Revenue Requirement True-up Adjustment
To be completed in conjunction with Attachment H-24A

Line No.	(1)		(2)	
	Reconciliation Adjustment for Schedule 1A Charges			
10	Actual Schedule 1A Costs for 12 Months Ended 12/31/2012 including True Up for 12 months ended 12/31/2011 (6)		$	-
11	Less: True Up Under/(Over) Recovery Adjustment for EKPC Sch. 1A for 12 months ended 12/31/2011 (7)		$	-
12	True-Up Principal Under(Over) Recovery before Interest	(Line 10 - Line 11)		$0.00
13	Less: Actual Sch. 1A Revenue Collected for 12 months Ended 12/31/2012 (8)			$0.00
14	True-Up Principal Under(Over) Recovery before Interest	(Line 12 - Line 13)	$	-
15	Monthly Interest Rate--Final FERC rate (9)			0.270%
16	Number of Months being Trued Up			12
17	Interest	(Line 5 x Line 6 x Line 7)	$	-
18	True Up Principal & Interest Under(Over) Recovery--Preliminary (10)	(Line 9 + Line 15)	$	-

Notes:
(6) Revenue requirement calculated using EKCP Attachment H-24A, Appendix A and actual cost information for the referenced year.
(7) EKPC Attachment H-24A, Appendix A, Line 6a for the referenced recovery year.
(8) Revenue received from PJM under PJM Tariff Schedules 7 and 8 for the EKPC Zone under Attachment H-24A for the referenced year.
(9) See: ***http://www.ferc.gov/legal/acct-matts/interest-rates.asp*** for the appropriate Month
10) Goes to Attachment H-24A, Appendix A, line 4.

East Kentucky Power Cooperative, Inc.
Depreciation Rates
Rates effective for year ending December 31, 2012

Line No.	FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D) %
			Transmission Plant (1)	
1	350	350010	Rights of Way (No depr on land)	-
2	353	353000	Station Equipment	1.790
3	353	353010	Station Equipment - ECS	1.790
4	354	354000	Towers and Fixtures - Trans Plant	0.710
5	355	355000	Poles & Fixtures	1.560
6	356	356000	Overhead Conductors & Devices	1.490
7	359	359000	Roads and Trails - Trans Plant	2.778
			General and Intangible Plant	
8	303	303000	Miscellaneous Intangible Plant	2.857
9	390	390000	Structures and Improvements - General Plant	4.778
10	391	391000	Office Furn & Equip - Gen Plant	0.200
11	391	391001	Office Furn & Equip - Peoplesoft	20.000
12	392	392000	Transportation Equipment	16.667
13	393	393000	Stores Equipment	10.000
14	394	394000	Tools, Shop & Garage Equipment	10.000
15	395	395000	Lab Equipment - General Plant	10.000
16	396	396000	Power Operated Equip - Gen Plant	10.000
17	397	397000	Communication Equipment - General Plant	10.000
18	397	397000	Communication Bldgs & Towers	3.030
19	397	397001	Communication Eq - ECS - General Plant	10.000
20	398	398000	Misc Equip - General Plant	10.000

NOTES:
(1) Depreciation Rates approved in KPSC Case No. 2006-00236.

East Kentucky Power Cooperative
Utilizing EKPC 2012 Form FF1 Data

Materials and Supplies (1)
Allocation of Account 163

Line No.		M&S	Percentage	Acct 163 (2)	Total M&S (3)
1	Production	$ 28,738,604	68.04%	-	
2	Transmission	13,399,855	31.72%	-	
3	Distribution	99,321	0.24%	-	
4	Total M&S	$ 42,237,780	100.00%	-	$ 13,399,855

Notes:
(1) Source - EKPC Form FF1 Ref Pg 227, Column C
(2) Unallocated M&S balance as of Year End
(3) To Attachment H-24A, Page 2 of 5, Line 27.

East Kentucky Power Cooperative, Inc.
Utilizing EKPC 2012 Form FF1 Data

Detail of Land Held for Future Use (1)

Line No.	Property Description	Transmission Related	Non-Transmission Related Portion	Reported on EKPC Form FF1
1	Proposed East London Substation Site	$ -	$27,462	$27,462
2		-	-	-
3		-	-	-
4		-	-	-
5		-	-	-
6		-	-	-
7	Balances	$ -	$27,462	$27,462

Notes:
(1) Source: EKPC Form FF1 Ref Pg 214, Account 105

East Kentucky Power Cooperative, Inc.
Utilizing EKPC 2012 Form FF1 Data

Safety and Non-Safety Related Advertising, Regulatory Expense, and PJM Integration Costs

Line No.		Source	EKPC
1	**General Advertising - Account 930.1**	Form FF1, P. 321, col. B	$590,674
2	Amount of Safety Related Advertising	Note 1	256,077
3	Amount of Non-Safety Related Advertising (1)		$334,597
4	**Regulatory Commission Expense - Account 928**	Note 2	$1,491,840
5	Less: Regulatory Expense unrelated to transmission (2)	Note 3	(1,289,337)
6	Regulatory Commission Expense Related to Transmission		$202,504
7	**PJM Integration Costs**	Note 4	
8	Consulting		$424,542
9	Legal Fees		$612,467
10	PJM Charges		$227,565
11	Equipment / Software Upgrades (Transmission Only)		$29,875
12			$1,294,449
14	Amortize for 3 years		$431,483

Notes:
(1) To Attachment H-24A, Page 3 of 5, Line 5
(2) Regulatory fees from Kentucky Public Service Commission, EKPC Form FF1, Ref Pg 321, Account 928
(3) Portion of regulatory expense for proceedings during the year that were not related to transmission, derived using the transmission function W/S allocator (See Attachment H-24A, page 4 of 5, line 16)
(4) Represents direct costs associated with EKPC's integration into PJM (transmission-related only) with three year amortization

East Kentucky Power Cooperative, Inc.
Utilizing EKPC 2012 Form FF1 Data

Balancing Authority Costs

Line No.			EKPC
	A&G Expense		
1	A&G Expense, Page 321, line 168, Current Year		$37,010,077
2	Adjustments		-
3	Adjusted A&G Expense - To Attachment H-24A, Page 3 of 5, Line 3		$37,010,077
	Transmission Expense		
4	Transmission Expense, EKPC Form FF1, Ref Pg 321, line 100, Current Year		$39,136,936
5	Adjustments		-
6	Adjusted Transmission Expense - To Attachment H-24A, Page 3 of 5, Line 1		$39,136,936
	Balancing Authority Costs in 561 through 561.3		
7	B.A. Costs in Transmission Expense on EKPC Form FF1, Ref Pg 321		$ 2,791,111
8	Less TVA Reliability Service Payments EKP Subaccount 561100		400,878
9	Adjusted B.A. Costs		$ 2,390,233
10	Total Balancing Authority Costs **(561.BA)** in Adj Transmission Exp	Note 1	$ -
11	Revenue Credits for Sched 1 / Acct 561 (2)	Note 2	$ 2,390,233

Notes:
(1) Costs related to BA activities not included in Schedule 1 Costs (will incur in future)
(2) To Attachment H-24A Page 4 of 5, Line 7

East Kentucky Power Cooperative, Inc.
Utilizing EKPC 2012 Form FF1 Data

Determination of Transmission Plant Included in OATT Ancillary Services

Line No.		EKPC	
1	Generation Step-up Transformers (1)	$	14,468,020
2	Sole use Property		-
3	Distribution Use		-
4	Transmission plant included in OATT Ancillary Services (2)	$	14,468,020

Notes:

(1) GSU capital costs that are included in the Transmission capital Account 353; amounts sourced from EKPC's PeopleSoft Asset Management System.

(2) To Attachment H-24A, page 4 of 5, Line 3

East Kentucky Power Cooperative, Inc.
Utilizing EKPC 2012 Form FF1 Data
Revenue Credits, Accounts 454, 456, 459 and GFA Revenues

Line No.				Account 454 EKPC
1	Per Books Total, Page 300 (Total Accts 440-459)		$	843,059,023
2	Tower Lease Revenues in per Books Total above			-
3	Rent from Electric Property FF1 Pg 300, Account 454	Note 1		112,335
4	Portion Attributable to Transmission			100.0%
5	Revenue Credit Applicable to Attachment H-24A		$	112,335
6	Total Account 454	Note 2	$	112,335
				Account 456, 459 EKPC
7	EKPC Form FF1, Page 300, Accounts 456 - 459	Note 3	$	16,386,049
	Remove Non-Transmission and Non-ISO Related Revenues:			
8	Production (Accts 456010, 456042, 456043 and 459000)			14,093,175
9	Common Transmission			-
10	Distribution			-
11	Customer Account (Accounts 456054 and 456057)			155,635
12	Administrative and General (Acct 456003)			15,754
13	Acct 456 less non-transmission and non-ISO revenue		$	2,121,485
14	Total EKPC Account 456130 Transmission Service			1,819,196
15	Adjusted Total Accounts 456 - 459		$	302,289
				GFA Revenues
16	Less: AEP Revenue for retained legacy agreement	Note 4	$	159,632
17	Total Other Transmission Revenue Credits	Note 5	**$**	**142,658**

Notes:
(1) Rent from KU for joint use of Rights of Way, Ref Pg 300, Page 2 of 2 (Acct 456)
(2) To Attachment H-24A, Page 4 of 5, line 34
(3) The amount shown in account 456 in FF1 includes revenues from sales of renewable energy credits included in account 459.
(4) Revenue from AEP GFA Account 456101- to Attachment H-24A, Page 1 of 5, Line 4.
(5) To Attachment H-24A, Page 4 of 5, Line 35

East Kentucky Power Cooperative, Inc.
Utilizing EKPC 2012 Form FF1 Data

Capital Structure
As of December 31, 2012
(In Dollars)

Line No.	Description			Percent	Cost (Note 4)	Weighted Cost
	Development of Cost of L.T. Interest					
1	Long term Interest (Note 1)	$	114,128,388			
2	Outstanding Long Term Debt (Note 2)	$	2,743,241,312			
3	**Average Cost of Debt (Line 1/Line 2)**		**4.160%**			
	Development of Required Return		**Value**			
4	Long Term Debt	$	2,743,241,312	88.37%	4.160%	3.677%
5	Proprietary Capital (Note 3)		360,946,072	11.63%	22.050%	2.564%
6	Total (Line 4 plus Line 5)	$	3,104,187,384			**6.241%**
7	**Effective TIER (Note 4)**				**TIER =**	**1.50**

Notes:
1. EKPC Form FF1 Ref Pg 117 Row 58, Column b, Current Year
2. EKPC Form FF1 for 2011, Ref Pg 112, Row 23 Bal at End of Year
3. EKPC Form FF1 for 2011, Ref Pg 112, Row 15, EOY Balance
4. Proprietary Capital Cost calculated to achieve TIER of 1.50. TIER value approved by KPSC in Case No. 2010-000167

East Kentucky Power Cooperative, Inc.

MONTHLY PEAKS IN KILOWATTS

Line No.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Average
1	EKPC - Monthly Total Native Load (1)	2,561,607	2,548,304	2,549,000	1,906,000	2,021,000	2,250,000	2,484,000	2,436,000	2,203,000	1,904,000	2,402,000	2,897,000	28,161,911	2,346,826
2	EKPC Firm Transmission for Others (kW)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**	**Average**
3															
4	Duke Kentucky (2)	7,267	7,200	5,750	5,263	7,105	7,463	9,630	7,052	6,413	5,575	5,789	6,953	81,460	6,788
5	KU/LGE (2)														
6	Bedford	3,588	3,771	2,604	2,101	2,642	3,190	3,106	3,130	2,813	2,296	2,589	2,695	34,525	2,877
7	Columbia	6,525	6,391	4,946	4,972	5,875	7,800	6,948	6,980	6,955	4,717	6,228	6,026	74,363	6,197
8	Columbia South	4,694	4,857	3,731	3,227	4,696	5,852	5,653	5,481	5,211	3,699	4,173	4,116	55,390	4,616
9	Falmouth	2,855	2,882	2,207	2,053	3,994	4,968	4,833	4,454	3,970	2,419	2,463	2,482	39,580	3,298
10	Garrard	149	168	227	457	15	18	17	383	354	146	246	168	2,349	196
11	Horse Cave	35,712	35,861	34,195	33,960	20,472	38,122	31,805	40,886	38,290	35,578	36,960	36,720	418,561	34,880
12	Hunters Bottom	2,288	2,339	1,735	1,453	1,533	2,036	1,832	1,723	1,487	1,359	1,674	1,742	21,201	1,767
13	Liberty	10,465	10,299	8,472	6,896	6,790	9,179	7,932	8,635	8,168	6,349	9,262	9,010	101,457	8,455
14	Mackville	797	821	555	444	506	558	575	515	426	515	543	623	6,878	573
15	Munfordville	5,321	5,753	3,470	4,365	5,773	7,766	7,051	7,401	6,517	4,048	4,922	4,892	67,278	5,607
16	Owingsville	5,020	4,905	4,007	3,881	4,854	6,144	5,659	5,994	5,734	4,212	4,297	4,267	58,975	4,915
17	Revelo	2,493	2,819	2,229	2,180	1,812	1,985	2,017	2,040	1,909	1,792	2,270	2,285	25,831	2,153
18	Russell Springs	8,741	9,495	6,122	4,960	5,917	7,916	7,033	7,065	6,974	5,793	6,526	6,803	83,345	6,945
19	Whitley City	5,962	6,105	4,897	4,059	3,684	4,733	4,229	4,112	3,863	3,626	5,052	5,103	55,426	4,619
20	Subtotal Transmission for KU/LGE	94,611	96,467	79,397	75,008	68,563	100,267	88,690	98,799	92,671	76,549	87,205	86,931	1,045,158	87,096
21	Total EKPC Firm Transmission for Others Subtotal (kW)	101,878	103,667	85,147	80,271	75,668	107,730	98,320	105,851	99,084	82,124	92,994	93,884	1,126,618	93,884
22	Total EKPC Monthly Transmission System Peak Load	2,663,485	2,651,971	2,634,147	1,986,271	2,096,668	2,357,730	2,582,320	2,541,851	2,302,084	1,986,124	2,494,994	2,990,884	29,288,529	2,440,711

Notes:

(1) Reflects the system peak demand (coincident peak) during a 60-minute clock hour. January 2013 and February 2013 information is sourced from the MV90 system; March 2013-December 2013 information is sourced from EKPC's forecasted demand.

ATTACHMENT H-24B
EKPC FORMULA RATE IMPLEMENTATION PROTOCOLS[1]

DEFINITIONS

“Annual Transmission Revenue Requirements” means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.

“Annual Update” means the posting and informational filing submitted by EKPC on or before May15 of each year that sets forth the EKPC Cost of Service (“COS”) for the subsequent Rate Year.

“Discovery Period” means the period after each annual Publication Date to serve information requests on EKPC as provided in these Protocols.

“First Rate Year” means the period that begins on June 1, 2013, and ends on May 31, 2014.

“Formal Challenge” means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission (“Commission”) as provided in these Protocols.

“Formula Rate” means these Formula Rate Implementation Protocols (to be included as Attachment H-24B of the PJM Interconnection, L.L.C. (“PJM”), FERC Electric Tariff (“PJM Tariff”)) and the Formula Rate Template.

“Formula Rate Template” means the collection of formulae and worksheets, unpopulated with any data, to be included as Attachment H-24A of the PJM Tariff.

“Preliminary Challenge” means a written challenge to the Annual Update submitted to EKPC as provided in these Protocols.

“Protocols” means these Formula Rate Implementation Protocols (to be included as Attachment H-24B of the PJM Tariff).

“Publication Date” means the date on which the Annual Update is posted.

“Rate Year” means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year.

“Review Period” means the period during which Interested Parties may review the calculations in the Annual Update.

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[1]East Kentucky Power Cooperative, Inc (“EKPC”) is an electric cooperative with outstanding debt from the United States Rural Utilities Service, and is not a FERC-jurisdictional public utility as that term is used in the Federal Power Act, 18 U.S.C. 824(f). In submitting and complying with these procedures and the formula rate, EKPC is not waiving its non-jurisdictional status and is not submitting to the FERC’s jurisdiction except to the extent that the Commission by law has jurisdiction to review EKPC’s rates by virtue of EKPC’s participation in PJM.

SECTION 1 <u>Annual Updates</u>

a. Beginning with the First Rate Year and for each Rate Year thereafter, the Annual Transmission Revenue Requirement calculated in accordance with Attachment H-24A and the Network Integration Transmission Service and Point-to-Point rates derived from Attachment H-24A shall be applicable to transmission services provided by PJM for the EKPC transmission pricing zone during the Rate Year.

b. On or before April 30 of each year, EKPC shall recalculate its Annual Transmission Revenue Requirement, producing the "Annual Update" for the upcoming Rate Year. EKPC shall:

(i) Arrange for PJM to post such Annual Update on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) as both a .pdf (Portable Document Format) document and a fully-functioning Excel file;

(ii) Provide contact information for inquiries concerning the Annual Update;

(iii) Send an email or other similar electronic communication to all parties affected by the Annual Update or which have previously requested such notification through procedures to be established by EKPC, informing the recipients that the Annual Update is available and providing the Uniform Resource Locator or other similar identifying location information from which the Annual Update can be obtained.

c. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the Commission, then the posting shall be due on the next business day.

d. The date on which the Annual Update is posted shall be that year's Publication Date.

e. Within two business days of the Publication Date, EKPC shall arrange for PJM to provide notice on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) of the time, date and location of an open meeting among interested parties ("Annual Meeting"). This Annual Meeting shall (i) permit EKPC to explain and clarify its Annual Update and (ii) provide interested parties an opportunity to seek information and clarifications from EKPC about the Annual Update. The Annual Meeting shall take place no sooner than ten (10) days after posting of the notice and no later than thirty (30) days after the Publication Date.

f. Inputs to the Formula Rate are based on EKPC's financial records and supporting work papers, which reflect:

(i) The RUS's Uniform System of Accounts, and

(ii) Applicable EKPC Form FF1[2] as each exists as of the later of the date of EKPC's initial filing of the Formula Rate or the last day of the calendar year immediately preceding the effective date of the most recent revision to the Formula Rate.

[2] EKPC is not a Public Utility as that term is used under the Federal Power Act and is therefore does not prepare or file a FERC Form No. 1 with the Commission. However, EKPC annually prepares a report on its finances and expenses containing information that matches that required for the FERC Form No. 1 and files that document with the Kentucky Public Service Commission. That document is designated as the EKPC Form FF1.

g. The Annual Update for the Rate Year:

(i) Shall, to the extent specified in the Formula Rate, be based upon the EKPC Form FF1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of EKPC consistent with Section 1.f above;

(ii) Shall, to the extent specified in the Formula Rate, provide the Formula Rate calculations and all inputs thereto, as well as support for data not otherwise available in the EKPC Form FF1 that are used in the Formula Rate;

(iii) Shall describe material changes, if any, in EKPC's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based that could or do materially affect the charges under the Formula Rate;

(iv) Shall be subject to challenge and review in accordance with the procedures set forth in this Attachment H-24B as to the appropriateness of the input data and the application of the Formula Rate according to its terms and the procedures in this Attachment H-24B;

(v) Except as provided for in Section 1.j below, shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate (i.e., all such modifications to the Formula Rate will require a filing with the FERC).

h. Formula Rate inputs for the Times Interest Earned Rate (TIER) and depreciation rates shall be stated values until changed pursuant to a filing made effective by the Commission.

SECTION 2 <u>Annual Review Procedures</u>

Each Annual Update shall be subject to the following Annual Review Procedures:

a. Interested parties shall have up to one hundred fifty (150) days after the Publication Date to review the inputs, supporting explanations, allocations and calculations ("Review Period") and to notify EKPC in writing, which notification may be made electronically, of any specific challenges.

b. Interested Parties shall have up to one hundred twenty (120) days after each annual Publication Date to serve reasonable information requests on EKPC. Such information requests shall be limited to what is necessary to determine if EKPC has properly applied the Formula Rate and the procedures of this Attachment H-24B Formula.

c. EKPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests.

d. Preliminary Challenges shall be subject to the resolution procedures and limitations in Section 3. Formal Challenges shall be filed pursuant to these Protocols and shall include the information required under 18 C.F.R. § 385.206 (b) (1), (2), (3), (4), and (7).

e. Preliminary or Formal Challenges related to material changes are not intended to serve as a means of pursuing other objections to the Formula Rate. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.

SECTION 3 Resolution of Challenges

a. If EKPC and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of EKPC to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the Commission, which shall be served on EKPC by electronic service on the date of such filing.

b. In any proceeding initiated by the Commission concerning the Annual Update or in response to a Formal Challenge, EKPC shall bear the burden of proving that it has correctly applied the terms of the Formula Rate.

c. Each Annual Update shall become final as to the Annual Transmission Revenue Requirement calculated for the Rate Year for which the Annual Update was calculated and no longer subject to challenge pursuant to these Protocols on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and the Commission has not initiated a proceeding to consider the Annual Update, or (ii) a final Commission order issued in response to a Formal Challenge or a proceeding initiated by the Commission to consider the Annual Update.

d. Except as specifically provided herein, nothing shall be deemed to limit in any way the right of EKPC to unilaterally file changes to the Formula Rate or any of its inputs (including, but not limited to, TIER or a replacement for TIER, transmission depreciation rates and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. These Protocols in no way limit the rights of EKPC or any Interested Party to initiate a proceeding at the Commission at any time with respect to the Formula Rate or any Annual Update consistent with the party's full rights under the FPA.

SECTION 4 Changes to Annual Informational Filings

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's EKPC Form FF1, or input data used for a Rate Year or calendar year that would have affected the Annual Update for that Rate Year or calendar year, or as the result of any Commission proceeding to consider a prior year's Annual Update, EKPC shall promptly notify the interested parties and provide a copy of the revised Annual Update to PJM for posting on the PJM's web site.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest.

Attachment E

EKPC Signature Page to CTOA

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

East Kentucky Power Cooperative, Inc.

By: Anthony S. Campbell
Name: Anthony S. Campbell
Title: President & CEO
Date: March 26, 2013

FERC rendition of the electronically filed tariff records in Docket No. ER13-01177-000
Filing Data:
CID: C000030
Filing Title: Revisions to the PJM OATT, OA & RAA re EKPC Integration
Company Filing Identifier: 975
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: Intra-PJM Tariffs
Tariff ID: 23
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
SCHEDULE 1A, OATT SCHEDULE 1A, 6.0.0, A
Record Narative Name: SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service
Tariff Record ID: 504
Tariff Record Collation Value: 294192230 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

Zone	**Rate ($/MWh)**
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030

Jersey Central Power & Light Company	0.0796
Metropolitan Edison Company	0.0796
Pennsylvania Electric Company	0.0796
Rockland Electric Company	0.2475
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company[1]	0.0797
Duquesne Light Company	0.0520
American Transmission Systems, Incorporated ("ATSI")	Rate updated annually Per Attachment H-21
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	Rate updated annually Per Attachment H-22
East Kentucky Power Cooperative, Inc. ("EKPC")	Per Attachment H-24

[1] Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$.0912//MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	1.41
Baltimore Gas and Electric Company	2.28
Delmarva Power & Light Company	2.17
PECO Energy Company	7.57
PP&L, Inc. Group	3.88
Potomac Electric Power Company	0.92
Public Service Electric and Gas Company	7.55
Jersey Central Power & Light Company	3.71
Metropolitan Edison Company	1.22
Pennsylvania Electric Company	1.90
Rockland Electric Company	0.57
Commonwealth Edison Company	41.42
AEP East Operating Companies	14.56
The Dayton Power and Light Company	2.41
Duquesne Light Company	1.20
American Transmission Systems, Incorporated ("ATSI")	3.05
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	4.17[2]
East Kentucky Power Cooperative, Inc. ("EKPC")	0.0

[2] Any change to this share must be made as a tariff filing under Section 205 of the Federal Power Act.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
SCHEDULE 7, OATT SCHEDULE 7, 4.0.0, A
Record Narative Name: SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point
Transmission Service
Tariff Record ID: 511
Tariff Record Collation Value: 299197951 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 7

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

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	32.114	2.676	0.6176	0.1235	0.0882
ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone[5/]	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone[6/]					
ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse PJMSettlement for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of $3.60/kw/year, $0.30/kw/mo., $0.0692/kw/week, $0.0099/kw/day-off-peak, or $0.0138/kw/day-on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall

not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
SCHEDULE 8, OATT SCHEDULE 8, 4..0, A
Record Narative Name: SCHEDULE 8
Non-Firm Point-To-Point Transmission Service
Tariff Record ID: 512
Tariff Record Collation Value: 299913054 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 8
Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily On-Peak[1/] Charge ($/kW)	Daily Off-Peak[2/] Charge ($/kW)	Hourly On-Peak[3/] Charge ($/MWh)	Hourly Off-Peak[4/] Charge ($/MWh)
Border of PJM	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE Zone	1.984	0.4580	0.0920	0.0650	5.7	2.72
BG&E Zone	1.306	0.3010	0.0600	0.0430	3.8	1.80
Delmarva Zone	1.615	0.3730	0.0750	0.0530	4.6	2.21
JCPL Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
MetEd Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
Penelec Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
PECO Zone	2.189	0.5051	0.1010	0.0722	6.3	3.01
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *	PPL: * AEC: 0.11 UGI: *	PPL: * AEC: 0.05 UGI: *
Pepco Zone	1.750	0.4040	0.0810	0.0580	5.0	2.40
PSE&G Zone	1.975	0.4557	0.0911	0.0651	5.7	2.71
AP Zone	1.737	0.4009	0.0802	0.0573	5.0	2.39

Rockland Zone	2.676	0.6176	0.1235	0.0882	7.7	3.67
ComEd Zone[5/]	[6/]					

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

AEP East Zone[7/] Nov. 1, 2005 SECA Ended W-JF Line In	AEP East Zone[7/]-	Rate Pursuant to Attachment H-14	Monthly Charge X 12 / 52 ~~0.24948~~	Weekly Charge / 5	Weekly Charge / 7	Daily On-Peak Charge / 16
Dayton Zone	Dayton Zone	1.306	0.3014	0.0603	0.0431	3.77
Duquesne Zone	Duquesne Zone	1.18	0.27	0.0540	0.0386	3.38
Dominion Zone[8/]	Dominion Zone[8/]					
ATSI Zone	ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

1/ Monday - Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ 7:00 a.m. up to the hour ending 11:00 p.m.

4/ 11:00 p.m. up to the hour ending 7:00 a.m.

5/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 9 below to determine the actual charge to the Transmission Customer.

6/ The charges for the ComEd zone are posted on PJM's website. In addition to the other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:
Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;
Monthly Rate - $/kW/month. = Annual Rate divided by 12;
Weekly Rate - $/kW/week = Annual Rate divided by 52;
Daily rate - $/kW/day = Weekly Rate divided by 5.
In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills

for years 2008-2014, consistent with the above methodology.

7/ The rates for non-firm point-to-point transmission service in the AEP Zone will be charged at the monthly, weekly, daily or hourly rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount, ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 8 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

8/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Monthly Charge - $/kW/month = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 12 divided by 1000 kW/MW;

Weekly Charge - $/kW/week = 12 times Monthly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7;

Hourly On-Peak Charge - $/MWh = Daily On-Peak Charge / 16 hours *1000 kW/MW;

Hourly Off-Peak Charge - $/ MWh = Daily Off-Peak Charge / 24 hours *1000 kW/ MW.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery or Daily Off-Peak Delivery, shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an Affiliate’s use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion, Losses and Capacity Export:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion

charges. If the Transmission Customer so elects, it shall either (a) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is positive, pay the higher of the applicable Transmission Congestion Charge or the applicable rate under section (1) above, or (b) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is negative, pay or be credited the sum of the applicable Transmission Congestion Charge and the rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay for any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

7) **Transmission Enhancement Charges:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd’s share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment (“SECA”) revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer’s bill in that month for service under this schedule.

9) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
SCHEDULE 10-NERC, OATT SCHEDULE 10-NERC, 4.0.0, A
Record Narative Name: SCHEDULE 10-NERC
North American Electric Reliability Corporation Charge
Tariff Record ID: 525
Tariff Record Collation Value: 309209393 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE

Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 10-NERC
North American Electric Reliability Corporation Charge

a) The North American Electric Reliability Corporation (NERC) is the Electric Reliability Organization (ERO) certified by the Federal Energy Regulatory Commission. Its purpose is to ensure the reliability of the interconnected bulk power system. This schedule will recover a share of NERC's costs of operations as set forth below.

b) PJM will charge each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the NERC Rate times the total quantity in MWhs of energy delivered to the load (including losses) that such customer serves in the PJM Region, excluding the Dominion Zone, the ATSI Zone and the EKPC Zone during such month. The exclusion applicable to the ATSI Zone shall expire on January 1, 2012.

c) A fixed rate will be charged for the first eleven billing periods of the current year. During the final billing period, a true-up component will be applied to adjust for any under or over collections for the current year.

d) NERC will submit final estimated costs to be recovered under this Schedule 10-NERC, determinants, and rates to the Transmission Provider no later than September 30th for the next calendar year. The Transmission Provider will post the rates for both components for the next calendar year no later than October 31st of the current year.

e) The NERCR shall be calculated each year in accordance with the formula:

$$NERCR=\frac{CYNC}{PJMNTHL}$$

where:

NERCR is the NERC Rate.

CYNC is the Current Year NERC Charges. These charges are the FERC approved funding for NERC for the year for which NERCR is being calculated. In the final billing for each calendar year a true-up component will be included applying any credit or deficiencies for the current year based on NERC's actual revenues as compared to NERC's FERC approved funding received under the schedule for the current year.

The Transmission Provider's NERC Total Hourly Load (PJMNTHL) is the estimated total quantity in MWhs of energy to be delivered to load (including losses) in the PJM Region, less the total quantity in MWhs of energy to be delivered to load (including losses) in the Dominion Zone, under Network Integration and Point-to-Point Transmission Service by all customers during the year for which NERCR is being calculated.

f) NERC is responsible for pursuing any and all defaults under this Schedule 10-NERC. Thus, the Transmission Provider will not deem any customer in default under the tariff for failure to pay any charges under this Schedule 10-NERC.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
SCHEDULE 10-RFC, OATT SCHEDULE 10-RFC, 3.0.0, A
Record Narative Name: SCHEDULE 10-RFC
Reliability First Corporation Charge
Tariff Record ID: 526
Tariff Record Collation Value: 309924496 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 10-RFC
Reliability First Corporation Charge

a) Reliability*First* Corporation (RFC) is one of the Regional Entities of NERC. Its purpose is to ensure the reliability of the interconnected bulk power system. This schedule will recover RFC's statutory costs of operations as set forth below.

b) PJM will charge each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the RFC Rate times the total quantity in MWhs of energy delivered to load (including losses) that such customer serves in the PJM Region, excluding the Dominion Zone, the ATSI Zone and the EKPC Zone, during such month. The exclusion applicable to the ATSI Zone shall expire on January 1, 2012.

c) A fixed rate will be charged for the first eleven billing periods of the current year. During the final billing period, a true-up component will be applied to adjust for any under or over collections for the current year.

d) NERC will submit final estimated costs to be recovered under this Schedule 10-RFC, determinants, and rates to the Transmission Provider no later than September 30th for the next calendar year. The Transmission Provider will post the rates for both components for the next calendar year no later than October 31st of the current year.

e) The RFCR shall be calculated each year in accordance with the formula:

$$\text{RFCR} = \frac{\text{CYRC}}{\text{PJMRTHL}}$$

where:

RFCR is the RFC Rate.

CYRC is the Current Year RFC Charges. These charges are the FERC approved funding for RFC for the year for which RFCR is being calculated. In the final billing for each calendar year a true-up component will be included applying any credit or deficiencies for the current year based on RFC's actual revenues as compared to RFC's FERC approved funding received under the schedule for the current year.

The Transmission Provider's RFC Total Hourly Load (PJMRTHL) is the estimated total quantity in MWhs of energy to be delivered to load (including losses) in the PJM Region, less the total quantity in MWhs of energy to be delivered to load (including losses) in the Dominion Zone, under Network Integration and Point-to-Point Transmission Service by all customers during the year for which RFCR is being calculated.

f) RFC is responsible for pursuing any and all defaults under this Schedule 10-RFC. Thus, the Transmission Provider will not deem any customer in default under the tariff for failure to pay any charges under this Schedule 10-RFC.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATTACHMENT C-3, OATT ATTACHMENT C-3 - Conversion of Service in the EKPC Zone, 0.0.0, A
Record Narative Name: OATT ATTACHMENT C-3 - Conversion of Service in the EKPC Zone
Tariff Record ID: 1566
Tariff Record Collation Value: 336740958 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT C-3

Conversion of Service in the EKPC Zone

The Office of the Interconnection is scheduled to become the Transmission provider for the EKPC Zone under the terms of this Tariff on June 1, 2013 and the EKPC tariff shall be superseded with respect to the EKPC Zone. Reservations purchased on the EKPC OASIS nodes prior to the integration of the EKPC Zone which remain in place following the integration date shall be converted to the appropriate service under this Tariff and subject to the rates, terms and conditions of this Tariff. In addition, interconnection requests under the EKPC tariff pending prior to the integration of the EKPC Zone shall be converted to requests for interconnection under this Tariff. This Attachment sets forth the principles that shall govern such conversions of service.

Customers who have reservations that need to be converted will be contacted directly by the Office of the Interconnection. Not all transmission service provided under the EKPC tariff exactly matches a service under this Tariff. Differences include variations in product definitions and PJM Region LMP pricing points. These variances in transmission requests will be converted into the defined product types explained below. The guidelines for the conversion of service are as follows:

1. All existing reservations will retain the same capacity (in megawatts) and will be

converted to a comparable PJM product and duration with the applicable point of receipt, point of delivery and path. Firm Point-to-Point Transmission Service redirected on a non-firm basis to Secondary Receipt or Delivery Points under the EKPC tariff prior to the EKPC integration date will be converted to service under this Tariff on the basis of the original firm points of receipt and delivery. Firm Point-to-Point Transmission Service redirected on a firm basis under section 22.2 (Modification on a Firm Basis) (or equivalent) of the EKPC tariff prior to the EKPC integration date will be converted to service under this Tariff on the basis of the modified firm points of receipt and delivery.

2. All EKPC reservations extending past the integration date must select Source and Sink LMP pricing points corresponding to the appropriate interface, where applicable, willing to pay through (or not), a new product if applicable. Willing to pay congestion (or not) must be determined no later than 12:00 noon EPT, 30 days prior to the EKPC integration start date. In the event the customer does not choose within the allotted deadline above, PJM will convert the service to the most closely analogous service under the PJM Tariff, in PJM's judgment. Willing to pay congestion is optional for non-firm and non-designated transmission service; Firm service, by definition, is willing to pay congestion. All converted service (as they exist) will be placed on the PJM OASIS no later than 30 days prior to the EKPC integration start date.

3. All EKPC import reservations will be converted to one of the following service types as defined by this Tariff or on the PJM OASIS. Spot market, Non-Firm Point-to-Point, Network Designated or Network Non-Designated. This choice will be made on an individual reservation basis, based on the scheduling intent of the reservation.

4. All existing EKPC Zone extended transmission requests (*i.e*. monthly, weekly, daily) that span multiple months will be converted to their largest individual components as defined on the PJM OASIS. For example, a monthly request from October 1 to December 1 will be converted to two individual monthly requests, October 1 to November 1, and November 1 to December 1; and daily request from January 1 of one year to January 1 of the next year will be converted to yearly service.

5. Sliding monthly service (*i.e*., monthly service that does not run from the first day of the given month to the last day of the given month) will be converted to weekly and daily service.

6. Sliding weekly service (*i.e*., weekly service that does not run from Monday at 00:00 to Sunday at 23:59) will be converted to daily service.

7. Transmission service that is not currently confirmed on the EKPC OASIS nodes and is in active status such as "Received," "Queued" or "Study" will be transferred to the integrated PJM OASIS node and will maintain its initial queued date.

8. All "Grandfathered" requests that exist on the EKPC OASIS nodes will require a reservation on the PJM OASIS node.

9. To facilitate the OASIS transition, from one month prior to the respective integration start date until such integration start date, requests for service that are active on or after such date one month prior to the integration start date should be made on both the pre-integration transmission owner or OASIS nodes and the PJM OASIS nodes.

10. Reservations will be converted based on the priority of the product.

11. Although the Office of the Interconnection will attempt to convert existing transmission reservations into comparable reservations on the PJM OASIS, there will be unique instances where this will not be possible (*e.g.*, reliability issues, etc.). In this case, reservations will be reviewed on a case-by-case basis. Transmission service that is not currently accepted on the EKPC Zone OASIS nodes and is in active state such as "Received," "Queued" or "Study" will be assigned the same status and queue position on the PJM OASIS as it had on the EKPC OASIS prior to conversion.

12 Converted Point-to-Point and Network transmission service reservations that extend beyond or begin after the integration commencement date will be posted to the PJM OASIS web page on an as-needed basis. The web page will identify the original EKPC Zone reservation and the new PJM OASIS reservation.

13. An Interconnection Request pending under the EKPC tariff at the time of the integration of the EKPC Zone shall be assigned the same priority date under this Tariff as such request had under the EKPC tariff immediately prior to such integration. The Interconnection Request will be assigned a PJM queue identifier such that the Interconnection Customer's priority date relative to existing PJM queued Interconnection Requests can be easily determined. All such Interconnection Requests will be integrated into PJM's existing Interconnection Queue(s), effective on the EKPC integration start date, and will be subject to the generation interconnection procedures under Parts IV and VI of this Tariff. On the EKPC integration date, PJM will assume the technical studies that have been started under the EKPC tariff. After the studies are complete, the Interconnection Customer will be required to pay for any Network Upgrades and/or Local Upgrades that are needed for the generating unit to qualify for Capacity

Interconnection Rights under this Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT H-24, OATT Attachment H-24 - EKPC Annual Transmission Rates, 0.0.0, A
Record Narative Name: ATTACHMENT H-24 -Annual Transmission Rates - EKPC
for Network Integration Transmission Service and Point-to-Point Transmission Service
Tariff Record ID: 1567
Tariff Record Collation Value: 361400540   Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT H-24
Annual Transmission Rates – EKPC
for Network Integration Transmission Service
and Point-to-Point Transmission Service

1. The Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service and Point-to-Point Transmission Service are the product of the formula shown in Attachment H-24A, and will be posted on the PJM website. The ATRR and the rates reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of East Kentucky Power Cooperative, Inc. ("EKPC").

2. The formula rate in this attachment shall be effective until amended by EKPC or modified by the Commission.

3. EKPC and American Electric Power shall be subject to the additional provisions of PJM Service Agreement No. 1530, Composite Interconnection Agreement between American Electric Power Service Corporation and East Kentucky Power Cooperative.

4. EKPC and Louisville Gas & Electric Company/Kentucky Utilities Company shall be subject to the additional provisions of PJM Service Agreement No. 3518, Service Agreement For Network Integration Transmission Service among PJM Interconnection, L.L.C., PJM Settlement Inc. and Louisville Gas and Electric Company/Kentucky Utilities Company.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT H-24A, OATT Attachment H-24A - EKPC Rate Formula Template, 0.0.0, A
Record Narative Name: OATT Attachment H-24A - EKPC Rate Formula Template
Tariff Record ID: 1568
Tariff Record Collation Value: 361400542   Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01

Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

DSS REVENUE REQUIREMENT (page 3, line 29)					$
VENUE CREDITS	Note A	Total	Allocator		
ount No. 454	(page 4, line 34)	$ 0	TP	0.00000	$
ount No. 456.1 (Net of Revenues from ndfathered Transactions)	(page 4, line 35)	0	TP	0.00000	
enues from Grandfathered Transactions	Note B	0	TP	0.00000	
enues from service provided by the ISO at a ount		0	TP	0.00000	
nsmission Enhancement Credit		0	TP	0.00000	
TAL REVENUE CREDITS (sum lines 2-5b)					$
e-up Adjustment	Note C				$
T REVENUE REQUIREMENT	(line 1 minus line 6 plus line 6a)				$
ISOR					
CP	Note D				
2 CP	Note E				
erved					
erved					
erved					
erved					
erved					
ual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$ 0.000			
ual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$0.000			
work Rate ($/kW/Mo)	(line 15 / 12)	$0.000			
nt-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$0.000			
		On-Peak Rate			Of
nt-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.000			
nt-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.000	Capped at weekly rate		
nt-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.000	Capped at weekly and daily rate		

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

(1) RATE BASE	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator		(5) Transmis (Col. 3 times
GROSS PLANT IN SERVICE						
Production	204.46.g	$	0	NA		
Transmission	206.58.g		0	TP	0.00000	$
Distribution	206.75.g		0	NA		
General & Intangible	204.5.g & 206.90.g		0	W/S	0.00000	
Common			0	CE	0.00000	
TOTAL GROSS PLANT(sum lines1-5)		$	0	GP=	0.000%	$
ACCUMULATED DEPRECIATION						
Production	219.20-24.c	$	0	NA		
Transmission	219.25.c		0	TP	0.00000	$
Distribution	219.26.c		0	NA		
General & Intangible	219.28.c		0	W/S	0.00000	
Common			0	CE	0.00000	
TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$	0			$
NET PLANT IN SERVICE						
Production	(line 1 - line 7)	$	0			
Transmission	(line 2 - line 8)		0			$
Distribution	(line 3 - line 9)		0			
General & Intangible	(line 4 - line 10)		0			
Common	(line 5 - line 11)		0			
TOTAL NET PLANT (sum lines 13-17)		$	0	NP=	0.000%	$
ADJUSTMENTS TO RATE BASE						
Account No. 281 (enter negative)	272.Total 281.k	$	-	NA	zero	$
Account No. 282 (enter negative)	274.Total 282.k		0	NP	0.00000	
Account No. 283 (enter negative)	276.Total 283.k		0	NP	0.00000	
Account No. 190	234.Total 190.c		0	NP	0.00000	
Account No. 255 (enter negative)	266.Total.h		0	NP	0.00000	
TOTAL ADJUSTMENTS (sum lines 19-23)		$	0			$
LAND HELD FOR FUTURE USE	214.Total.d, Note F	$	-		0.00000	$
WORKING CAPITAL						
CWC	calculated, Note G	$	0			
Materials & Supplies	227.8.c		0	TE	0.00000	
Prepayments (Account 165)	110.46.c, Note G		0	GP	0.00000	
TOTAL WORKING CAPITAL (sum lines 26-28)		$	0			$
RATE BASE (sum lines 18, 24, 25, & 29)		$	0			$

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator		(5) Transmis (Col. 3 times
&M						
Transmission	321.100	$	0	TE	0.00000	$
Less Account 565	321.Acct 565		0	TE	0.00000	
&G	321.168		0	W/S	0.00000	
Less FERC Annual Fees	N/A		0	W/S	0.00000	
Less Non-safety Advertising	Note H		0	W/S	0.00000	
Less KPSC Regulatory Expenses	Note H		0			
Plus Transmission Related Regulatory Exp	Note H		0	TE	0.00000	
Plus Prorated PJM Transition Expense	Note H		0			
Common			0	CE	0.00000	
Transmission Lease Payments			0		0.00000	
OTAL O&M (sum lines 1, 2a, 3, 5a, 6,7 less lines 1a, 2, 4, 5)		$	0			$
EPRECIATION EXPENSE						
Transmission	336.7.f	$	0	TP	0.00000	$
General and Intangible	336.9.f		0	W/S	0.00000	
Common	336.10.f		0	CE	0.00000	
OTAL DEPRECIATION (Sum lines 9-11)		$	0			$
AXES OTHER THAN INCOME TAXES						
ABOR RELATED						
Payroll	Note I	$	0	W/S	0.00000	$
Highway and vehicle	Note I		0	W/S	0.00000	
LANT RELATED						
Property	Note I		0	GP	0.00000	
Gross Receipts			0	NA	NA	
Other			0	GP	0.00000	
Payments in lieu of taxes			0	GP	0.00000	
OTAL OTHER TAXES (sum lines 13-19)		$	0			$
COME TAXES	Note J					
T=1 - {[(1-SIT) * (1-FIT)] / (1 - SIT * FIT * p)} =			0.000000%			
CIT=(T/1-T) * (1-(WCLTD/R)) =			0.000000%			
1 / (1 - T) = (from line 21)			0.0000			
nortized Investment Tax Credit	266.8.f (enter negative)		0			
come Tax Calculation (line 22 * line 28)		$	0	NA		$
C adjustment (line 23 * line 24)			0	NP	0.00000	
tal Income Taxes	(line 25 plus line 26)	$	0			$

ETURN				
[Rate Base (page 2, line 30) * Rate of Return (page 4, line 29)]	$	0	NA	$
EVENUE REQUIREMENT (sum lines 8,12, 20, 27, 28)	$	0		$

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.	**TRANSMISSION PLANT INCLUDED IN ISO RATES**			
1	Total transmission plant (page 2, line 2, column 3)			
2	Less transmission plant excluded from ISO rates			
3	Less transmission plant included in OATT Ancillary Services	See Supporting Exhibit, Page 5 of 8, Line 4, (Note K)		
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)			
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)			
	TRANSMISSION EXPENSES			
6	Total transmission expenses (page 3, line 1, column 3)			
7	Less transmission expenses included in OATT Ancillary Services	Note L		
8	Included transmission expenses (line 6 less line 7)			
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)			
10	Percentage of transmission plant included in ISO Rates (line 5)			
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)			
	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP
12	Production	354.18.b	0	0.0
13	Transmission	354.19.b	0	0.0
14	Distribution	354.20.b	0	0.0
15	Other	354.21,22,23,24.b	0	0.0
16	Total (sum lines 12-15)		0	
	COMMON PLANT ALLOCATOR (CE)		%	
17	Electric	200.3.c	0.00	
18	Gas	201.3.d	0.00	
19	Water	201.3.e	0.00	
20	Total (sum lines 17 - 19)		0.00	
	RETURN (R)			
21		Long Term Interest (117, sum of 58.c through 65.c)		
22		Preferred Dividends (118.29c) (positive number)		
	Development of Cost of Capital:			
23	Long Term Debt	(112.23c) See Supporting Exhibit, Page 7 of 8		
24	Proprietary Capital	(112.15.c)		

25	Less Account 216.1	(112.12.c) (enter negative)		
26		Total Capital	(sum lines 23-25)	
			$	%
27	Long Term Debt (112.23c)	Note M	0	0.00
28	Proprietary Capital (112.15.c)	Note N	0	0.00
29	Total (sum lines 27-28)		0	
30	Effective TIER	Note O		

REVENUE CREDITS

	ACCOUNT 447 (BUNDLED SALES FOR RESALE)		(310-311)
31	a. Bundled Non-RQ Sales for Resale (311.x.k)		
32	b. Bundled Sales for Resale included in Divisor on page 1		
33	Total of (a)-(b)		
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	See Supporting Exhibit, Page 6 of 8, Line 3 (Note P)	
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)	See Supporting Exhibit, Page 6 of 8, Line 17 (Note Q)	

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EKPC 20__ Form FF1 Data
East Kentucky Power Cooperative, Inc.

General Note:	**References to pages in this formulary rate are indicated as: (page#, line#, col.#)** **References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)**

Note Letter	
A	The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Formulary Rate Template.
B	Revenue from AEP Grandfathered Agreement. See Rev Cred Support, Attachment H-24A, Supporting Exhibit, page 6 of 8, line 16
C	Calculated in accordance with the EKPC Formulary Rate Protocols in Attachment H-24B of this Tariff. See Appendix C
D	EKPC 1 CP is EKPC's highest Monthly Firm Transmission System Peak Load based on the source data as described in Note 1 of Attachment H-24A, Page 8 of 8, plus transmission service provided for others over the EKPC transmission system, plus wheel-out to EKPC load connected to AEP/KP, Duke Ky, and LGE/KU See Attachment H-24A, Supporting Exhibit, Page 8 of 8
E	EKPC 12 CP is EKPC's Monthly Firm Transmission System Peak Load based on the source data as described in Note 1 of Attachment H-24A, Page 8 of 8, plus transmission service provided for others over the EKPC transmission system, plus wheel-out to EKPC load connected to AEP/KP, Duke Ky, and LGE/KU See Attachment H-24A, Supporting Exhibit, Page 8 of 8
F	Identified in EKPC Form FF1 as being non-transmission related. See Attachment H-24A, Supporting Exhibit, Pg 2 of 8
G	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3 of 5, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on EKPC Form FF1, Ref Pg 110, line 46.
H	Line 5 - Remove non-safety related advertising included in Account 930.1. See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 3 Line 5a - Remove Total Regulatory Commission Expenses - See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 4 Line 5b - Add Back Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting - See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 6 Line 5c - Add EKPC costs relating to PJM transition. See Attachment H-24A, Supporting Exhibit, Page 3 of 8, Line 14
I	In accordance with RUS accounting standards, EKPC allocates all payroll and property taxes

to the functional account. Labor- and plant-related taxes are already included in the appropriate transmission account.

J As a member-owned non-profit RUS generation and transmission cooperative, EKPC is exempt from state and from federal income taxes under 501(c)(12) of Internal Revenue Code

K Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, included in Account 561. See Attachment H-24A, Supporting Exhibit, Page 4 of 8.

M Debt cost rate = long-term interest (line 21) / long term debt (line 27).

N Proprietary Capital Cost calculated to achieve TIER of 1.50

O TIER value approved by KPSC in Case No. 2010-000167

P Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

Q Net of retained legacy transactions. See Attachment H-24A, Supporting Exhibit, page 6 of 8.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT H-24A Appx A, OATT Attachment H-24A Appendix A - EKPC Schedule 1A, 0.0.0, A
Record Narative Name: OATT Attachment H-24A Appendix A - EKPC Schedule 1A
Tariff Record ID: 1569
Tariff Record Collation Value: 361400544 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

Attachment H-24A
Appendix A
Page 1 of 1
For the 12 months ended 12/31/20__

East Kentucky Power Cooperative, Inc.
Transmission Formula Rate Revenue Requirement
Utilizing EKPC 20__ Form FF1 Data
For Rates Effective June 1, 20__

Schedule 1A Rate Calculation

Line No.		Source		Revenue Requirement
chedule 1A	Annual Revenue Requirements			
1	Total Load Dispatch & Scheduling (Account 561)	Supporting Exh, page 4 of 8, line 11	$	0
	Less allocated amount for steam production [(Line 6c/Line 6b) * Line 1]		$	0
	Total Load Dispatch & Scheduling (Account 561) excluding Steam		$	0
2	Revenue Credits for Schedule 1A	Note 1	$	-
3	Net Schedule 1A Revenue Requirement for Zone		$	0
4	Less: True Up Under/(Over) Recovery for 12 months ended 12/31/20__	Note 2	$	-

5	Schedule 1A Recovery Amount for 12 Months ended		$ 0
chedule 1A Rate Calculations		Note 3	
6	2012 Requirements Sales for Resale	Note 4	0
6a	Plus Non-requirements Sales for Resale	Note 5	0
6b	Subtotal	Note 6	0
6c	Less Equivalent Steam		0
6d	Net MWh		0
7	Schedule 1A rate $/MWh (Line 5 / Line 6)	(Line 3 / Line 6)	$0.0000

Notes:

(1) Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of EKPC's zone during the year used to calculate rates under Attachment H-24A
(2) Amount from Attachment H-24A, Appendix C, line 13 for stated year.
(3) Sourced from EKPC Form FF1, Ref Pg 401, adjusted for equivalent steam sold
(4) FF1, Ref Page 401, Line 23
(5) FF1, Ref Page 401, Line 24
(6) FF1, Ref Page 401, Footnote

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT H-24A Appx B, OATT Attachment H-24A Appendix B - EKPC RTEP, 0.0.0, A
Record Narative Name: OATT Attachment H-24A Appendix B - EKPC RTEP
Tariff Record ID: 1570
Tariff Record Collation Value: 361400546 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

Attachment H-24A
Appendix B
Page 1 of 2
For the 12 months ended 12/31/20__

Rate Formula Template
Utilizing Attachment H-24A
East Kentucky Power Cooperative, Inc.
RTEP - Transmission Enhancement Charges
To be completed in conjunction with Attachment H-24A

(1)	(2)	(3)	
	Attachment H-24A Page, Line, Col.	Transmission	All
TRANSMISSION PLANT			
Gross Transmission Plant - Total	Attachment H-24A, p 2, line 2 col 5 (Note A)	0	
Net Transmission Plant - Total	Attachment H-24A, p 2, line 14 col 5 (Note B)	0	

O&M EXPENSE

Total O&M Allocated to Transmission	Attachment H-24A, p 3, line 8 col 5	0
Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.00%
GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE		
Total G&C Depreciation Expense	Attachment H-24A, p 3, lines 10 & 11, col 5 (Note H)	0
Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.00%
TAXES OTHER THAN INCOME TAXES		
Total Other Taxes	Attachment H-24A, p 3, line 20 col 5	-
Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.00%
Annual Allocation Factor for Expense	**Sum of lines 4, 6 and 8**	
INCOME TAXES		
Total Income Taxes	Attachment H-24A, p 3, line 27 col 5	-
Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	0.00%
RETURN		
Return on Rate Base	Attachment H-24A, p 3, line 28 col 5	25,293,160
Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	6.58%
Annual Allocation Factor for Return	**Sum of lines 11 and 13**	

Note

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-24A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-24A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-24A, page 3 line 12.

F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G The Network Upgrade Charge is the value to be used in PJM OATT Schedule 26.

H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in Attachment H-24A Appendix B, page 2, column 9.

For the 12 months ended 12/31/20__

East Kentucky Power Cooperative, Inc.
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
ject ne	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**
		(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)
		$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -
		$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -
		$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -
Totals									$0	$0

RTEP Transmission Enhancement Charges for Attachment H-24A, Page 1, Line 5c

<u>Note Letter</u>

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-24A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-24A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-24A, page 3 line 12.

F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G The Network Upgrade Charge is the value to be used in Schedule 26.

H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT H-24A Appx C, OATT Attachment H-24A Appendix C - EKPC True-up, 0.0.0, A
Record Narative Name: OATT Attachment H-24A Appendix C - EKPC True-up
Tariff Record ID: 1571
Tariff Record Collation Value: 361400548   Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

Rate Formula Template
Utilizing Attachment H-24A

East Kentucky Power Cooperative, Inc.
Calculation of Prior Year Transmission Revenue Requirement True-up Adjustment
To be completed in conjunction with Attachment H-24A

ne o.	(1)		(2)
	Reconciliation Adjustment for Transmission Revenue Requirements		
	Actual Transmission Revenue Requirement for 12 Months Ended 12/31/20__ including True Up for 12 months ended 12/31/20__ (1)		$
	Less: True Up Under/(Over) Recovery Adjustment for EKPC Appendix H-24A for 12 months ended 12/31/20__ (2)		$
	Transmission revenue requirements for the 12 months ended12/31/20__	(Line 1 - Line 2)	$
	Less: Actual Transmission Revenue Collected for 12 months Ended 12/31/20__(3)		$
	True-Up Principal Under(Over) Recovery before Interest	(Line 3 - Line 4)	$
	Monthly Interest Rate--Final FERC rate (4)		0.0
	Number of Months being Trued Up		
	Interest	(Line 5 x Line 6 x Line 7)	$
	True Up Principal & Interest Under(Over) Recovery--Preliminary (5)	(Line 9 + Line 15)	$

Notes:
(1) Revenue requirement from Page 1 of 5, line 7 of Attachment H-24A for the referenced year.
(2) EKPC Attachment H-24A, page 1 of 5, Line 6a for the referenced recovery year
(3) Revenue received under PJM Tariff Schedules 7 and 8 under Attachment H-24A for the referenced year.
(4) See: ***http://www.ferc.gov/legal/acct-matts/interest-rates.asp*** for the appropriate Month
(5) Goes to Attachment H-24A , page 1 of 5, line 6a

Rate Formula Template
Utilizing Attachment H-24A

East Kentucky Power Cooperative, Inc.
Calculation of Prior Year Transmission Revenue Requirement True-up Adjustment
To be completed in conjunction with Attachment H-24A

e No.	(1)		(2)
	Reconciliation Adjustment for Schedule 1A Charges		
0	Actual Schedule 1A Costs for 12 Months Ended 12/31/20__ including True Up for 12 months ended 12/31/20__ (6)		$
1	Less: True Up Under/(Over) Recovery Adjustment for EKPC Sch. 1A for 12 months ended 12/31/20__ (7)		$
2	True-Up Principal Under(Over) Recovery before Interest	(Line 10 - Line 11)	$
3	Less: Actual Sch. 1A Revenue Collected for 12 months Ended 12/31/20__ (8)		$
4	True-Up Principal Under(Over) Recovery before Interest	(Line 12 - Line 13)	$
5	Monthly Interest Rate--Final FERC rate (9)		0.0
6	Number of Months being Trued Up		
7	Interest	(Line 5 x Line 6 x Line 7)	$
8	True Up Principal & Interest Under(Over) Recovery--Preliminary (10)	(Line 9 + Line 15)	$

Notes:
(6) Revenue requirement calculated using EKCP Attachment H-24A, Appendix A and actual cost information for the referenced year.
(7) EKPC Attachment H-24A, Appendix A, Line 6a for the referenced recovery year.
(8) Revenue received from PJM under PJM Tariff Schedules 7 and 8 for the EKPC Zone under Attachment H-24A for the referenced year.
(9) See: ***http://www.ferc.gov/legal/acct-matts/interest-rates.asp*** for the appropriate Month
10) Goes to Attachment H-24A, Appendix A, line 4.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT H-24A Appx D, OATT Attachment H-24A Appendix D - EKPC Depreciation Rates, 0.0.0, A
Record Narative Name: OATT Attachment H-24A Appendix D - EKPC Depreciation Rates
Tariff Record ID: 1572
Tariff Record Collation Value: 361400550 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1

Associated Filing Identifier:

Attachment H-24A
Appendix D

East Kentucky Power Cooperative, Inc.
Depreciation Rates
Rates effective for year ending December 31, 20__

Line No.	FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D)
				%
			Transmission Plant (1)	
1	350	350010	Rights of Way (No depr on land)	-
2	353	353000	Station Equipment	0.000
3	353	353010	Station Equipment - ECS	0.000
4	354	354000	Towers and Fixtures - Trans Plant	0.000
5	355	355000	Poles & Fixtures	0.000
6	356	356000	Overhead Conductors & Devices	0.000
7	359	359000	Roads and Trails - Trans Plant	0.000
			General and Intangible Plant	
8	303	303000	Miscellaneous Intangible Plant	0.000
9	390	390000	Structures and Improvements - General Plant	0.000
10	391	391000	Office Furn & Equip - Gen Plant	0.000
11	391	391001	Office Furn & Equip - Peoplesoft	0.000
12	392	392000	Transportation Equipment	0.000
13	393	393000	Stores Equipment	0.000
14	394	394000	Tools, Shop & Garage Equipment	0.000
15	395	395000	Lab Equipment - General Plant	0.000
16	396	396000	Power Operated Equip - Gen Plant	0.000
17	397	397000	Communication Equipment - General Plant	0.000
18	397	397000	Communication Bldgs & Towers	0.000
19	397	397001	Communication Eq - ECS - General Plant	0.000
20	398	398000	Misc Equip - General Plant	0.000

NOTES:

(1) Depreciation Rates approved in KPSC Case No. ______________.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT H-24B, OATT Attachment H-24B - EKPC Implementation Protocols, 0.0.0, A
Record Narative Name: OATT Attachment H-24B - EKPC Implementation Protocols
Tariff Record ID: 1573
Tariff Record Collation Value: 361400552 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT H-24B
EKPC FORMULA RATE IMPLEMENTATION PROTOCOLS[1]

DEFINITIONS

"Annual Transmission Revenue Requirements" means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.

"Annual Update" means the posting and informational filing submitted by EKPC on or before May15 of each year that sets forth the EKPC Cost of Service ("COS") for the subsequent Rate Year.

"Discovery Period" means the period after each annual Publication Date to serve information requests on EKPC as provided in these Protocols.

"First Rate Year" means the period that begins on June 1, 2013, and ends on May 31, 2014.

"Formal Challenge" means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission ("Commission") as provided in these Protocols.

"Formula Rate" means these Formula Rate Implementation Protocols (to be included as Attachment H-24B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.

"Formula Rate Template" means the collection of formulae and worksheets, unpopulated with any data, to be included as Attachment H-24A of the PJM Tariff.

"Preliminary Challenge" means a written challenge to the Annual Update submitted to EKPC as provided in these Protocols.

"Protocols" means these Formula Rate Implementation Protocols (to be included as Attachment H-24B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update.

----

[1]East Kentucky Power Cooperative, Inc ("EKPC") is an electric cooperative with outstanding debt from the

United States Rural Utilities Service, and is not a FERC-jurisdictional public utility as that term is used in the Federal Power Act, 18 U.S.C. 824(f). In submitting and complying with these procedures and the formula rate, EKPC is not waiving its non-jurisdictional status and is not submitting to the FERC's jurisdiction except to the extent that the Commission by law has jurisdiction to review EKPC's rates by virtue of EKPC's participation in PJM.

SECTION 1 <u>Annual Updates</u>

a. Beginning with the First Rate Year and for each Rate Year thereafter, the Annual Transmission Revenue Requirement calculated in accordance with Attachment H-24A and the Network Integration Transmission Service and Point-to-Point rates derived from Attachment H-24A shall be applicable to transmission services provided by PJM for the EKPC transmission pricing zone during the Rate Year.

b. On or before April 30 of each year, EKPC shall recalculate its Annual Transmission Revenue Requirement, producing the "Annual Update" for the upcoming Rate Year. EKPC shall:

(i) Arrange for PJM to post such Annual Update on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) as both a .pdf (Portable Document Format) document and a fully-functioning Excel file;

(ii) Provide contact information for inquiries concerning the Annual Update;

(iii) Send an email or other similar electronic communication to all parties affected by the Annual Update or which have previously requested such notification through procedures to be established by EKPC, informing the recipients that the Annual Update is available and providing the Uniform Resource Locator or other similar identifying location information from which the Annual Update can be obtained.

c. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the Commission, then the posting shall be due on the next business day.

d. The date on which the Annual Update is posted shall be that year's Publication Date.

e. Within two business days of the Publication Date, EKPC shall arrange for PJM to provide notice on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) of the time, date and location of an open meeting among interested parties ("Annual Meeting"). This Annual Meeting shall (i) permit EKPC to explain and clarify its Annual Update and (ii) provide interested parties an opportunity to seek information and clarifications from EKPC about the Annual Update. The Annual Meeting shall take place no sooner than ten (10) days after posting of the notice and no later than thirty (30) days after the Publication Date.

f. Inputs to the Formula Rate are based on EKPC's financial records and supporting work papers, which reflect:

(i) The RUS's Uniform System of Accounts, and

(ii) Applicable EKPC Form FF1[2] as each exists as of the later of the date of EKPC's initial filing of the Formula Rate or the last day of the calendar year immediately preceding the effective date of the most recent revision to the Formula Rate.

[2] EKPC is not a Public Utility as that term is used under the Federal Power Act and is therefore does not prepare or file a FERC Form No. 1 with the Commission. However, EKPC annually prepares a report on its finances and expenses containing information that matches that required for the FERC Form No. 1 and files that document with the Kentucky Public Service Commission. That document is designated as the EKPC Form FF1.

g. The Annual Update for the Rate Year:

(i) Shall, to the extent specified in the Formula Rate, be based upon the EKPC Form FF1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of EKPC consistent with Section 1.f above;

(ii) Shall, to the extent specified in the Formula Rate, provide the Formula Rate calculations and all inputs thereto, as well as support for data not otherwise available in the EKPC Form FF1 that are used in the Formula Rate;

(iii) Shall describe material changes, if any, in EKPC's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based that could or do materially affect the charges under the Formula Rate;

(iv) Shall be subject to challenge and review in accordance with the procedures set forth in this Attachment H-24B as to the appropriateness of the input data and the application of the Formula Rate according to its terms and the procedures in this Attachment H-24B;

(v) Except as provided for in Section 1.j below, shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate (i.e., all such modifications to the

Formula Rate will require a filing with the FERC).

h. Formula Rate inputs for the Times Interest Earned Rate (TIER) and depreciation rates shall be stated values until changed pursuant to a filing made effective by the Commission.

SECTION 2 Annual Review Procedures

Each Annual Update shall be subject to the following Annual Review Procedures:

a. Interested parties shall have up to one hundred fifty (150) days after the Publication Date to review the inputs, supporting explanations, allocations and calculations ("Review Period") and to notify EKPC in writing, which notification may be made electronically, of any specific challenges.

b. Interested Parties shall have up to one hundred twenty (120) days after each annual Publication Date to serve reasonable information requests on EKPC. Such information requests shall be limited to what is necessary to determine if EKPC has properly applied the Formula Rate and the procedures of this Attachment H-24B Formula.

c. EKPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests.

d. Preliminary Challenges shall be subject to the resolution procedures and limitations in Section 3. Formal Challenges shall be filed pursuant to these Protocols and shall include the information required under 18 C.F.R. § 385.206 (b) (1), (2), (3), (4), and (7).

e. Preliminary or Formal Challenges related to material changes are not intended to serve as a means of pursuing other objections to the Formula Rate. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.

SECTION 3 Resolution of Challenges

a. If EKPC and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of EKPC to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the Commission, which shall be served on EKPC by electronic service on the date of such filing.

b. In any proceeding initiated by the Commission concerning the Annual Update or in response to a Formal Challenge, EKPC shall bear the burden of proving that it has correctly applied the terms of the Formula Rate.

c. Each Annual Update shall become final as to the Annual Transmission Revenue Requirement calculated for the Rate Year for which the Annual Update was calculated and no longer subject to challenge pursuant to these Protocols on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and the Commission has not initiated a proceeding to consider the Annual Update, or (ii) a final Commission order issued in response to a Formal Challenge or a proceeding initiated by the Commission to consider the Annual Update.

d. Except as specifically provided herein, nothing shall be deemed to limit in any way the right of EKPC to unilaterally file changes to the Formula Rate or any of its inputs (including, but not limited to, TIER or a replacement for TIER, transmission depreciation rates and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. These Protocols in no way limit the rights of EKPC or any Interested Party to initiate a proceeding at the Commission at any time with respect to the Formula Rate or any Annual Update consistent with the party's full rights under the FPA.

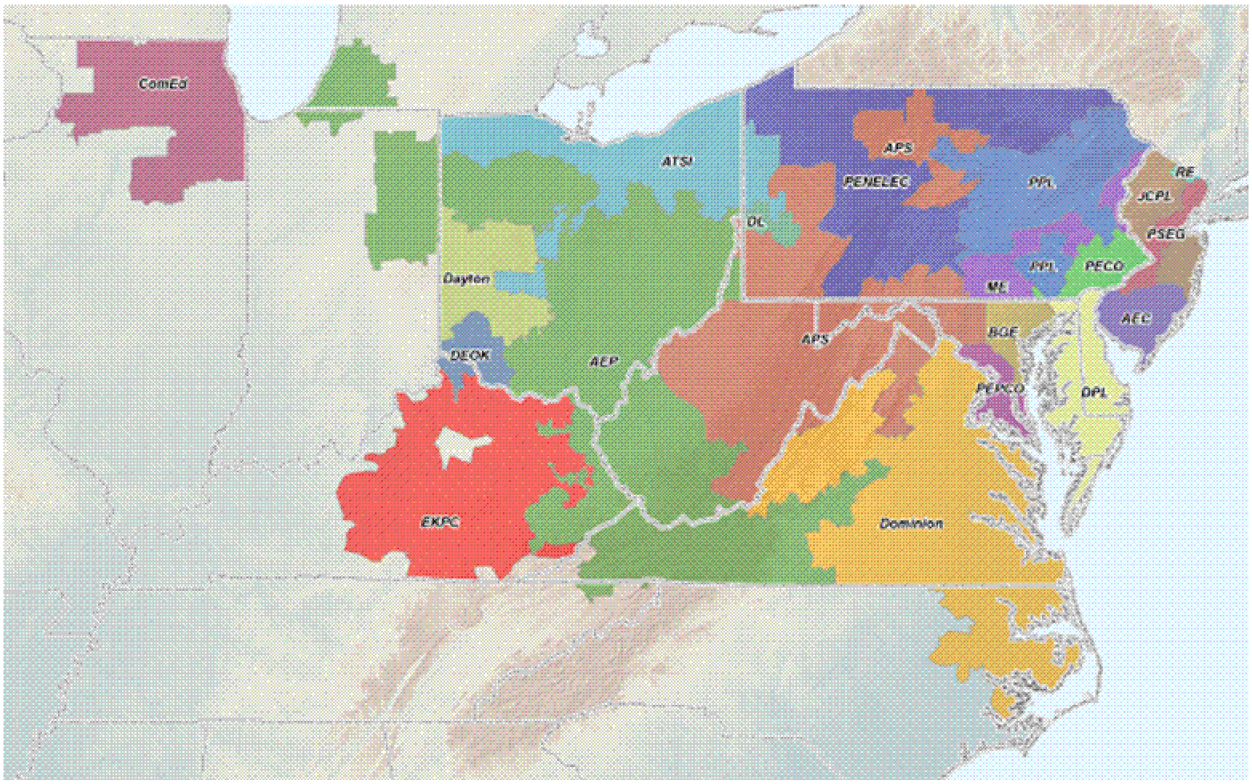
SECTION 4 Changes to Annual Informational Filings

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's EKPC Form FF1, or input data used for a Rate Year or calendar year that would have affected the Annual Update for that Rate Year or calendar year, or as the result of any Commission proceeding to consider a prior year's Annual Update, EKPC shall promptly notify the interested parties and provide a copy of the revised Annual Update to PJM for posting on the PJM's web site.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest.

Tariff Record ID: 547
Tariff Record Collation Value: 362127015   Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT J
PJM Transmission Zones



FULL NAME	**SHORT NAME**
Pennsylvania Electric Company	PENELEC
Allegheny Power	APS
PPL Electric Utilities Corporation	PPL
Metropolitan Edison Company	ME
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

Duquesne Light Company	DL
Virginia Electric and Power Company	Dominion
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK
East Kentucky Power Cooperative, Inc.	EKPC

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT K Appx Sec 3.2, OATT Attachment K Appendix Sec 3.2 - Market Buyers, 17.0.0, A
Record Narative Name: 3.2 Market Buyers.
Tariff Record ID: 585
Tariff Record Collation Value: 389300929 Tariff Record Parent Identifier: 583
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

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

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

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

3.2.2 Regulation.

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

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total

Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource‘s actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource‘s actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource‘s actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource‘s actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the

Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying* the assigned MW(s) by the performance Regulation market-clearing price, *by* the *ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources*, and *by* the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

Correlation Score = $\mathbf{r}_{\text{Signal,Response}(\delta,\delta+5\text{ Min});}$
δ=0 to 5 Min

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

Delay Score = Abs ((δ- 5 Minutes) / (5 Minutes)).

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

Energy Score = 1 - 1/n ∑ Abs (Error);

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

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

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

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

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

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

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

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

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and
>
> where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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

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

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage.

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

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

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

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

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

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen

Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

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

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

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$\text{Ramp\_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLAtime}_{t-1})}$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

$$\text{Ramp\_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLAtime}_{t-1})}$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

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

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

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

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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

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

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

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the

Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non- Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

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

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

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

where:

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

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

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

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

3.2.7 Billing.

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

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

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Associated Filing Identifier:

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.
>
> (ii) Long-term FTR auction revenues remaining after distributions

made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; 2013 for the EKPC Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Prior to the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights allocated at the aggregate load buses in a Zone. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the

Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the
megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Prior to the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights sink at the aggregate load buses in a Zone. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the

PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual

Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
ATTACHMENT L, OATT ATTACHMENT L, 6.0.0, A
Record Narative Name: ATTACHMENT L
List of Transmission Owners
Tariff Record ID: 933
Tariff Record Collation Value: 423625873 Tariff Record Parent Identifier: 357
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT L
List of Transmission Owners

Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Atlantic City Electric Company
Baltimore Gas and Electric Company
NAEA Rock Springs, LLC
Delmarva Power & Light Company
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
East Kentucky Power Cooperative, Inc.
Hudson Transmission Partners, LLC
Jersey Central Power & Light Company
Metropolitan Edison Company
Neptune Regional Transmission System, LLC
Old Dominion Electric Cooperative
Pennsylvania Electric Company
PECO Energy Company
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Trans-Allegheny Interstate Line Company
UGI Utilities, Inc.
Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power
Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.
The Dayton Power and Light Company
AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)
Duquesne Light Company
Virginia Electric and Power Company
Linden VFT, LLC
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Hamilton, OH

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
ATTACHMENT DD.5.10, OATT ATTACHMENT DD.5.10 Auction Clearing Requirements, 13.0.0, A
Record Narative Name: 5.10Auction Clearing Requirements
Tariff Record ID: 1153
Tariff Record Collation Value: 665330687 Tariff Record Parent Identifier: 1142
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2),

(iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

- For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target ; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and

Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the

Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2015, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $128,000 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	140,000
BGE, PEPCO (“CONE Area 2”)	130,600
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC (“CONE Area 3”)	127,500
PPL, MetEd, Penelec (“CONE Area 4”)	134,500
Dominion (“CONE Area 5”)	114,500

B) Beginning with the 2016-2017 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W

Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2015-2016 Delivery Year to which the Applicable H-W Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-

Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the Zone in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OA Sch 1 Sec 3.2, OA Schedule 1 Sec 3.2 - Market Buyers, 17.0.0, A
Record Narative Name: OA Schedule 1 Section 3.2 - Market Buyers
Tariff Record ID: 784
Tariff Record Collation Value: 809781493 Tariff Record Parent Identifier: 782
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

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

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

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

3.2.2 Regulation.

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

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the

Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource‘s actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource‘s actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational

Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource‘s actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource‘s actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying* the assigned MW(s) by the performance Regulation market-clearing price, *by* the *ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources*, and *by* the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = \mathbf{r}_{\text{Signal,Response}(\delta,\delta+5\text{ Min});} \quad \delta=0 \text{ to } 5 \text{ Min}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

Delay Score = Abs ((δ- 5 Minutes) / (5 Minutes)).

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

Energy Score = 1 - 1/n ∑ Abs (Error);

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the

Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

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

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for

Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

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

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

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

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

> LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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

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

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage.

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

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

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

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

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

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

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$\text{Ramp\_Request}_t = \left(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}\right) \Big/ \left(\text{UDSLAtime}_{t-1}\right)$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

$$\text{Ramp\_Request}_t = \left(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}\right) \Big/ \left(\text{UDSLAtime}_{t-1}\right)$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

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

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

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

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the

Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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

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

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

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve

Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

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

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

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

where:

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

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

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

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

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

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

3.2.7 Billing.

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

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

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
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Record Narative Name: OA Schedule 1 Sec 7.4 Allocation of Auction Revenues.
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7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection,

such revenues shall be distributed in accordance with subsection (c)(ii) of this section;

(ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;

(iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

(i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; 2013 for the EKPC Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Prior to the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights allocated at the aggregate load buses in a Zone. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the
megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round.

Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Prior to the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights sink at the aggregate load buses in a Zone. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge").

A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer’s Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer’s Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer’s network service peak load; or 2) the customer’s Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC’s rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection’s assessment of the buyer’s ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OA SCHEDULE 12, OA SCHEDULE 12 PJM MEMBER LIST, 13.0.0, A
Record Narative Name: OA SCHEDULE 12 - PJM MEMBER LIST
Tariff Record ID: 931
Tariff Record Collation Value: 915616737 Tariff Record Parent Identifier: 633
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 12 -
PJM MEMBER LIST

A123 Systems, Inc.
AC Energy, LLC
AC Power Financial Corp.
Acciona Energy North America Corporation (AENAC)

A&C Management Group LLC
AEP Appalachian Transmission Company, Inc.
AEP Energy, Inc.
AEP Energy Partners, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP Retail Energy Partners, LLC
AEP West Virginia Transmission Company, Inc.
AES Armenia Mountain Wind, LLC
AES Beaver Valley LLC
AES Energy Storage, LLC
AES Laurel Mountain, LLC
Agway Energy Services, LLC
Air Liquide Industrial US, LP
Air Products & Chemicals, Inc.
AK Steel Corporation
Akula Energy, LLC
Alabama Power Company
Alcoa Power Marketing LLC
Algonquin Energy Services, Inc.
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, LLC
ALLETE, Inc. d/b/a Minnesota Power
Alliant Energy Corporate Services, Inc.
Alpha Gas and Electric, LLC
Ambit Northeast, LLC
Ameren Energy Marketing Company
American Efficient, Inc.
American Illuminating Company, LLC
American Municipal Power, Inc.
American Power Partners, LLC
American PowerNet Management, L.P.
American Transmission Company, LLC
American Transmission Systems Inc.
Amerigreeen Energy, Inc.
Anbaric Northeast Transmission Development Company, LLC
AP Gas & Electric (IL), LLC
AP Gas & Electric (MD), LLC
AP Gas & Electric (OH), LLC
AP Gas and Electric (NJ), LLC
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Appalachian Power Company
Apple Group LLC
APX Power Markets, Inc.

Aquenergy Systems Inc.
Aquila, Inc. d/b/a Aquila Networks
ArcelorMittal USA, LLC
ArcLight Energy Marketing, L.L.C.
Aspen Merchant Energy, LP
Associated Electric Cooperative, Inc.
Astral Energy LLC
Atlantic City Electric Company
Atlantic Grid Operations A, LLC
Automated Algorithms, LLC
Balance Power Systems, LLC
Baltimore Gas and Electric Company
Bank of America N.A.
Barclays Bank PLCBE Red Oak LLC
Barclays Capital Services, Inc
Bartram Lane, LLC
BBPC LLC d/b/a/ Great Eastern Energy
Beacon Power Corporation
Beech Ridge Energy LLC
Benton Foundry, Inc.
BG Energy Merchants, LLC
Big Rivers Electric Corporation
Big Sandy Peaker Plant, LLC
Big Savage, LLC
Big Sky Wind, LLC
Biogas Energy Solutions LLC
Bishop Hill Energy LLC
BJ Energy, LLC
Black Oak Capital, LLC
Black Oak Energy, LLC
Black River Commodity Energy Fund LLC
Black River Commodity Fund, Ltd.
Blackstone Wind Farm, LLC
Blackstone Wind Farm II, LLC
Blast Electric, LLC
Bluefin Electricity Trading, LLC
Bluegrass Generating Company, LLC
Blue Pilot Energy, LLC
Blue Ridge Power Agency, Inc.
BNP Paribas Energy Trading GP
Border Energy Electric Services, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Lavallette, New Jersey
Borough of Madison, New Jersey
Borough of Milltown

Borough of Mont Alto
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights
Borough of South River, New Jersey
Borough of Tarentum
Bounce Energy PA, LLC
BP Alternative Energy North America Inc.
BP Energy Company
Brighten Energy, LLC
Brookfield Energy Marketing Inc.
Brookfield Energy Marketing, LP
Brookfield Power Piney & Deep Creek LLC
Brookfield Renewable Energy Marketing US LLC
Bruce Power Inc.
Buckeye Power, Inc.
Buckeye Energy Brokers, Inc.
Calpine Bethlehem, LLC
Calpine Energy Services, L.P.
Calpine Mid Atlantic Marketing, LLC
Calvert Cliffs Nuclear Power Plant, Inc.
Cambria Cogen Company
Camp Grove Wind Farm, LLC
Canadian Wood Products – Montreal, Inc. dba CWP Energy
Cargill Power Markets, LLC
Carolina Power & Light Company
Castlebridge Energy Group, LLC
Cayler Trading Group, LLC
CBK Group, LTD
CCES LLC
Centaurus Energy Master Fund, LP
Central Transmission, LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy, LLC
Champion Energy Marketing LLC
Champion Energy Services, LLC
Chesapeake Transmission LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Cincinnati Bell Energy, LLC
Cinergy Retail Sales, LLC
Cinnamon Bay, LLC
Citigroup Energy Inc.
Citizen’s Electric Company of Lewisburg, PA
City of Batavia, Illinois

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Geneva (The)
City of Hamilton
City of New Martinsville – WV
City of Naperville
City of Philadelphia
City of Philippi – West VA
City of Rochelle
CleanLight Power + Energy, LLC
Clearview Electric, Inc.
Cleveland Electric Illuminating Company (The)
CMS Energy Resource Management Company
Coaltrain Energy LP
Cobalt Capital Partners, LLC
Cogentrix Virginia Leasing Corporation
Commercial Utility Consultants, Inc.
Commerce Energy Inc.
Commonwealth Chesapeake Company, LLC
Commonwealth Edison Company
Community Energy, Inc.
Comperio Energy LLC dba ClearChoice Energy
Con Edison Energy, Inc.
Conch Energy Trading, LLC
Conectiv Energy Supply, Inc.
ConocoPhillips Company
Consolidated Edison Company of New York, Inc.
Consolidated Edison Solutions, Inc.
Constellation Energy Commodities Group, Inc.
Constellation Energy Control and Dispatch, LLC
Constellation Energy Power Choice, Inc.
Constellation Energy Projects & Services Group, Inc.
Constellation NewEnergy, Inc.
Constellation Power Source Generation, Inc.
Consumers Energy Company
Coral Power, L.L.C.
Cordova Energy Company LLC
CornerStone Power Development, LLC
Corona Power LLC
Corporate Services Support Corp.
County of Frederick, VA
Covanta Delaware Valley, L.P.
Covanta Energy Group, Inc.
Covanta Essex Company
Covanta Union, Inc.
CP Energy Marketing (US) Inc.

CPV MARYLAND, LLC
CPV Shore, LLC
Credit Suisse Energy LLC
Credit Suisse (USA), Inc.
Crete Energy Venture, LLC
CrunchEnergy, LLC
Customized Energy Solutions, Ltd.
Cygnus Energy Futures, LLC
Darby Energy, LLLP
Dart Container Corporation of Pennsylvania
Dayton Power & Light Company (The)
DB Energy Trading LLC
DC Energy LLC
DC Energy Mid-Atlantic, LLC
DEL LIGHT INC.
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Demand Response Partners, Inc.
Demansys Energy, LLC
Denver Energy, LLC
Devonshire Energy, LLC
Diamond State Generation Partners, LLC
Direct Energy Business, LLC
Direct Energy Services, LLC
Discount Energy Group, LLC
Discount Energy, LLC
Discount Power, Inc.
Divine Power, Inc.
Division of the Public Advocate of State of Delaware
Dominion Energy Marketing, Inc.
Dominion Retail, Inc.
Domtar Paper Company, LLC
Downes Associates, Inc.
DPL Energy, LLC
DPL Energy Resources, LLC
DTE Energy Supply, Inc.
DTE Energy Trading, Inc.
Duke Energy Carolinas, LLC
Duke Energy Commercial Asset Management
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Shared Services, Inc.
Duquesne Conemaugh LLC
Duquesne Keystone LLC
Duquesne Light Company
Duquesne Light Energy, LLC

Duquesne Power LLC
DynArb, LLC
Dynasty Power Inc.
Dynegy Energy Services, Inc.
Dynegy Marketing and Trade, LLC
Dynegy Power Marketing, Inc.
Dyon, LLC
E Minus LLC
E.ON Climate & Renewables North America Inc.
Eagle Energy, LLC
Eagle Point Power Generation LLC
East Coast Power Linden Holdings, L.L.C.
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
Ebensburg Power Company
eCap Network, LLC
EcoGrove Wind, LLC
EDF Industrial Power Services (IL), LLC
EDF Trading North America, LLC
Edison Mission Marketing & Trading, Inc.
Edison Mission Solutions, LLC
EDP Renewables North America, LLC
E.F. Kenilworth, Inc.
EFS Parlin Holdings, LLC
El Cap II, LLC
Elkem Metals Company-Alloy LP
El Paso Marketing, LLC
Elliot Bay Energy Trading, LLC
Elwood Energy LLC
EMC Development Company, Inc.
EME Homer City Generation, L.P.
Emera Energy Services, Inc.
Employers' Energy Alliance of Pennsylvania, Inc.
Emporia Hydropower Limited Partnership
ENBALA Power Networks, Inc.
Endure Energy, LLC
Energetix, Inc.
Energy America, LLC
Energy Algorithms LLC
Energy Analytics
Energy Analytics, Inc.
Energy Authority, Inc. (The)
EnergyConnect, Inc.
Energy Consulting Services, LLC
Energy Cooperative of America, Inc.
Energy Cooperative Association of Pennsylvania

Energy Curtailment Specialists, Inc. (ECS)
Energy Exchange Direct, LLC
Energy Exchange International, LLC
Energy International Power Marketing Corporation
Energy Investments, LLC
Energy-Links, LLC
Energy.me Midwest llc d/b/a energy.me
Energy Plus Holdings LLC
Energy Service Providers, Inc.
Energy Spectrum Inc.
EnergyUSA – TPC Corp.
EnerNOC, Inc.
EnerPenn USA, LLC
Enerwise Global Technologies, Inc.
Engage Energy America LLC
Enserco Energy, Inc.
Entegra Power Services LLC
EP Enterprises Incorporated
EP Ocean Peaking Power, LLC
EP Rock Spring, LLC
EPEX, Inc.
EPIC NJ/PA, L.P.
ERA MA, LLC
Essential Power, LLC
Ethical Electric Benefit Co.
Evergreen Community Power
Evraz Claymont Steel
Exel Power Sources, LLC
Exelon Business Services Company, LLC
Exelon Energy Company (The)
Exelon Generation Company, LLC
Exelon New England Power Marketing, Limited Partnership
Falcon Energy, LLC
FirstEnergy Solutions Corp.
First Point Power, LLC
Florida Power Corporation dba Progress Energy Florida, Inc.
Forest Investment Group, LLC
Fowler Ridge Wind Farm LLC
Fowler Ridge II Wind Farm LLC
FPL Energy Marcus Hook LP
Franklin Power LLC
Freepoint Commodities LLC
Fulcrum Energy Limited
Galt Power, Inc.
Gateway Energy Services Corporation
GDF SUEZ Energy Resources NA, Inc.

GDF Suez Retail Energy Solutions, LLC
Gelber Energy LLC
GenOn Energy Management, LLC
GenOn Potomac River, LLC
GenOn Power Midwest, LP
Georgia Power Company
Gerdau Ameristeel Energy, Inc
Glacial Energy of New Jersey, Inc.
Grand Ridge Energy LLC
Grand Ridge Energy II LLC
Grand Ridge Energy III LLC
Grand Ridge Energy IV LLC
Grand Ridge Energy V LLC
Granger Energy of Honey Brook, LLC
Grant Energy, Inc.
Grays Ferry Cogeneration Partnership
Great American Power, LLC
Great Bay Energy I, LLC
Great Bear Hydropower, Inc.
Green Mountain Energy Company
Greenpoint Trading Group, LLC
GRG ENERGY LLC
GSG 6, LLC
Gulf Power Company
G&G Energy, Inc.
Hagerstown Light Department
Handsome Lake Energy, LLC
Harrison REA, Inc. – Clarkesburg, WV
Hartz Group (The)
Hawks Nest Hydro LLC
Hazleton Generation LLC
Hemsworth Capital LP
Hess Corporation
Hess NEC, LLC
Hexis Energy Trading, LLC
Highland North LLC
Highlands Energy Group, LLC (The)
HIKO Energy, LLC
Hill Energy Resource & Services, LLC
Holcim (US), Inc.
Hoosier Energy REC, Inc.
HOP Energy, LLC
Horizon Power and Light, LLC
H-P Energy Resources, LLC
H.Q. Energy Services (U.S.), Inc.
HSBC Technology Services (USA), Inc.

Hudson Energy Services, LLC
Hudson Transmission Partners, LLC
Iberdrola Renewables, LLC
Icetec.com, Inc.
IDT Energy, Inc.
Illinois Citizens Utility Board
Illinois Municipal Electric Agency
Independence Energy Group, LLC
Independent Energy Consultants, Inc.
Indiana Michigan Power Company
Indiana Municipal Power Agency
Indiana Office of Utility Consumer Counselor (IN OUCC)
Industrial Energy Users-Ohio
Industrial Metal Treating Corp.
Ingenco Wholesale Power, LLC
Innoventive Power LLC
Integrys Energy Services, Inc.
IntelliGen Resources, LP
Intergrid Mideast Group LLC
International Paper Company
Interstate Gas Supply, Inc.
Interstate Power and Light Company
Invenergy LLC
Invenergy Nelson LLC
Invictus Capital Management, Ltd
IPR-GDF Suez Energy Marketing North America, Inc.
Iron Energy LLC
J. Aron & Company
J3 Energy Group (The)
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
JAS Energy, LLC
James River Cogeneration Company
Jersey-Atlantic Wind, LLC
Jersey Central Power & Light Company
Jersey Green Energy, LLC
JP Morgan Ventures Energy Corporation
JPTC, LLC
Juice Technologies, LLC
Kansas City Power & Light
KAP Analytics, LLC
Kasia C LLC
Katmai Energy, LLC
Keil & Sons, Inc dba Systrum Energy
Kentucky Municipal Power Agency
Kentucky Power Company
KeyTex Energy LLC

KeyTex Energy Solutions LLC
KFW Energy, LLC
Kimberly-Clark Corporation
Kimmel Energy Associates
Kingsport Power Company
Knedergy, LLC
KOREnergy, Ltd.
Krayn Wind LLC
Kuehne Chemical Company, Inc.
Kynetic Energy Solutions L&P Electric Inc., dba Leggett & Platt Electric Inc.
LCG Consulting
LDH Energy Funds Trading, Ltd.
Lee River Proprietary Strategies, Inc.
Legacy Energy Group, LLC (The)
Legends Energy Group, Inc.
Lehigh Capital, LLC
Lehigh Portland Cement Company
Lehman Brothers Commodity Services, Inc.
Letterkenny Industrial Development Authority – PA
Liberty Electric Power, LLC
Liberty Hill Power LLC
Liberty Power Corp., L.L.C.
Liberty Power Delaware, LLC
Liberty Power District of Columbia LLC
Liberty Power Holdings LLC
Liberty Power Maryland, LLC
Lilabell Energy LLC
Lincoln Generating Facility, LLC
Linde, Inc.
Linde Energy Services, Inc.
Linden VFT LLC
LM Power, LLC
Long Island Lighting Company d/b/a LIPA
Longview Power, LLC
Louis Dreyfus Energy Services L.P.
Louisville Gas and Electric Company/Kentucky Utilities Company
Lower Electric, LLC
Lower Mount Bethel Energy, LLC
LSP-Kendall Energy, LLC
LSP Safe Harbor Holdings, LLC
LSP University Park, LLC
Luminary Consulting LLC
Mac Trading, Inc.
Macquarie Energy, LLC
Madison Gas and Electric Co.
Madison Windpower LLC

MAG Energy Solution, Inc.
Magnolia Energy, LP
Major Energy Electric Services, LLCMaple Analytics, LLC
Marathon Power, LLC
Marina Energy, LLC
Maryland Office of People's Counsel
MC Squared Energy Services, LLC
MeadWestvaco Corporation
Meadow Lake Wind Farm, LLC
Meadow Lake Wind Farm II, LLC
Meadow Lake Wind Farm III, LLC
Meadow Lake Wind Farm IV, LLC
MEG Generating Company, LLC
Mehoopany Wind Energy LLC
Mercuria Energy America, Inc.
Merrill Lynch Commodities, Inc.
MET MA LLC
Metropolitan Edison Company
Metropolitan Energy, L.L.C.
Miami Valley Lighting, LLC
Michigan Public Power Agency
Microsoft Corporation
MidAmerican Energy Company
MidAtlantic Power Partners
Middlesex County Utilities Authorities
Midwest Energy Trading East LLC
Midwest Generation, LLC
Millennium Inorganic Chemicals, Inc.
Mint Energy, LLC
Mississippi Power Company
Monmouth Energy, Inc.
Monongahela Power Company d/b/a/ Allegheny Power
Monterey MA, LLC
Monterey MAF, LLC
Morgan Stanley Capital Group, Inc.
Morris Cogeneration, L.L.C Mt. Carmel Cogeneration Inc.
Morse Energy LLC
Mosaic Power, LLC
Moxie Liberty LLC
MP2 Energy NE, LLC
NASDAQ OMX Commodities Clearing, LLC
Natgasco, Inc.
National Railroad Passenger Corp. – AMTRAK
Nautilus Solar Energy, LLC
NedPower Mount Storm, LLC
Negawatt Business Solutions, Inc.

NEPM II, LLC
Neptune Regional Transmission System, LLC
NERC-Middlesex Solar I, LLC
New Covert Generating Company, LLC
New Jersey Division of the Ratepayer Advocate
New York State Electric & Gas Corporation
Newel Trading Group, LLC
NextEra Energy Power Marketing, LLC
NextEra Energy Services Illinois, LLC
NextEra Energy Services New Jersey, LLC
NJR Clean Energy Ventures Corporation
Noble American Gas & Power Corp.
Noble Americas Energy Solutions, LLC
Nordic Energy Services LLC
North America Power Partners LLC
North American Energy Credit and Clearing-Delivery LLC
North American Natural Resources – SBL, LLC
North American Power and Gas, LLC
Northampton Generating Company
Northeast Maryland Waste Disposal Authority
Northeast Transmission Development, LLC
Northeastern REMC
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northeast Utilities Service Company
Northern Illinois Municipal Power Agency
Northern States Power Company
Northern Virginia Electric Cooperative - NOVEC
NorthPoint Energy Solutions, Inc.
Northport USA, LLC
NorthWrite Energy Group, LLC
NRG Power Marketing, LLC
NuEnergen, LLC
NYSEG Solutions, Inc.
NYX Energy Corp.
Oasis Power, LLC dba Oasis Energy
Occidental Power Services, Inc.
Oceanside Power, LLC
Office of the People's Counsel for the District of Columbia
Ohio Consumer's Counsel
Ohio Edison Company
Ohio Power Company
Ohms Energy Company, LLC
Old Dominion Electric Cooperative
Olympus Power, LLC
Ontario Power Generation Inc.

Ontario Power Generation Energy Trading, Inc.
Ontelaunee Power Operating Company, LLC
Orion Asset Management, LLC
Owensboro Municipal Utilities
Ozark International, Inc.
P.H. Glatfelter Company
Pacific Summit Energy LLC
Palama, LLC
Palmco Power DC, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power OH, LLC
Palcom Power PA, LLC
Panda Power Corporation
Panther Creek Power Operating, LLC
Parma Energy LLC
PATH Allegheny Transmission Company, LLC
PATH West Virginia Transmission Company, LLC
Pattern Recognition Technologies, Inc.
Patton Wind Farm, LLC
Paulding Wind Farm II LLC
PBF Power Marketing, LLC
PECO Energy Company
Pedricktown Plant Holdings, LLC
PEI Power Corporation
PEI Power II, LLC
Penncat Corporation
Pennsylvania Electric Company
Pennsylvania Office of Consumer Advocate
Pennsylvania Power Company
Pennsylvania Renewable Resources, Associates
People's Power & Gas, LLC
Pepco Energy Services, Inc.
Perspective Energy USA LLC
PG Energy Services Inc. d/b/a/ PG Energy Power Plus
Phalanx Energy Services, LLC
Pioneer Prairie Wind Farm, LLC
Pirin Solutions, Inc.
PJS Capital, LLC
Planet Energy (Maryland) Corp.
Planet Energy (Pennsylvania) Corp.
Planet Energy (USA) Corp.
Plymouth Rock Energy, LLC
Potomac Edison Company (The) d/b/a/ Allegheny Power
Potomac Electric Power Company

Potomac Power Resources, Inc.
Powerex Corporation
PowerSecure, Inc.
PPL Brunner Island, LLC
PPL Electric Utilities Corporation dba PPL Utilities
PPL EnergyPlus, LLC
PPL EnergyPlus Retail, LLC
PPL Holtwood, LLC
PPL Ironwood, LLC
PPL Martins Creek, LLC
PPL Montour, LLC
PPL Susquehanna, LLC
Prairieland Energy, Inc.
Praxair, Inc.
Premcor Refining Group, Inc. (The)
Primary Power, LLC
Procter & Gamble Paper Products Company (The)
Property Endeavors LLC
Providence Heights Wind, LLC
PSEG Energy Resources & Trade LLC
Public Power & Utility of Maryland, LLC
Public Power & Utility of New Jersey, LLC
Public Power, LLC
Public Power, LLC [CT]
Public Service Electric and Gas Company
Pure Energy, Inc.
Quasar Energy Group, LLC
Quiet Light Trading, LLC
QVINTA, Incorporated
Raiden Commodities LP
Rainbow Energy Marketing Corporation
Rational Systems LLC
RBC Energy Services LP
RC Cape May Holdings, LLC
Realgy, LLC
Red Oak Power, LLC
Red Wolf Energy Trading, LLC
Reliable Power, LLCReliant Energy Electric Solutions, LLC
Reliant Energy Northeast, LLC
Reliant Energy Services, Inc.
Reliant Energy Solutions East, LLC
Renaissance Power, LLC
ResCom Energy, LLC
Reservoir Creek Energy, L.P.
Respond Power, LLC
RG Steel Sparrows Point, LLC

RI-Corp. Develement, Inc.
Richards' Energy Group (The)
Richland-Stryker Generation LLC
Riverside Generating Company, L.L.C.
RLTec US Inc.
Rochester Gas and Electric Corporation
Rockland Electric Company
Rolling Hills Generating, L.L.C.
Roth Rock Wind Farm, LLC
Royal Bank of Canada
RRI Energy Services, LLC
S.J. Energy Partners, Inc.
Safe Harbor Water Power Corporation
Safeway Inc.
Sailor's Star Co.
Santana Energy Services
Saracen Energy East LLC
Saracen Energy Power Trading LP
Saracen Power LLC
Schuylkill Energy Resources, Inc.
Scylla Energy LLC
Select Energy New York, Inc.
Sempra Generation
Servidyne Systems, LLC
SESCO ENTERPRISES LLC
Sheetz, Inc.
Siemens Energy, Inc.
SIG Energy, LLLP
Site Controls, Inc.
Smart Grid Solutions, LLC
SMART Papers Holdings, LLC
Smart Wire Grid, Inc.
Solios Power LLC
Solios Power Mid-Atlantic Trading, LLC
Solios Power Mid-Atlantic Virtual LLC
South Carolina Electric & Gas Company
Southeastern Chester County Refuse Authority
Southeastern Power Administration
Southern Indian Gas and Electric Company d/b/a Vectren Power Supply Inc.
Southern Power Company
Southern Maryland Electric Cooperative, Inc.
South Jersey Energy Company
South Jersey Energy Solutions, L.L.C.
Spark Energy, L.P.
Sperian Energy Corp
Starion Energy PA, Inc.

STATARB INVESTMENTS LLC
Stoney Creek Wind Farm, LLC
Strategic Transmission LLC
Stream Energy Columbia, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
STS Energy Partners LP
Sugar Creek Power Company, LLC
Summit Energy, LLC
SunCoke Energy, Inc
Sunoco, Inc. (R&M)
Sunoco Power Marketing, L.L.C.
Superior Plus Energy Services, Inc.
Sustainable Star LLC
Syncarpha Solar, LLC
Synergy Solutions Group LLC
Tangent Energy Solutions, Inc.
TAQA Gen X LLC
Target Corporation
TEC Trading, Inc.
Telemagine, Inc.
Tenaska Power Services Co.
Tenaska Virginia Parners, L.P.
Tennessee Valley Authority (The)
TERM Power & Gas, LLC
Texas Retail Energy, LLC
Thomas Jackson Management, Inc.
Thurmont Municipal Light Company
Tilton Energy, LLC
Titan Gas and Power
Toledo Edison Company (The)
Torofino Trading, LLC
Town of Berlin, Maryland
Town of Front Royal, Virginia
Town of Williamsport
Trademark Merchant Energy, LLC
Traditum Group LLC
Trans-Allegheny Interstate Line Company
TransAlta Energy Marketing (US) Inc.
TransCanada Power Marketing, Ltd.
Trans-Elect Development Company, LLC
TransMarket Group LLCUBS AG, acting through its London Branch
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trinity Powerworks, Inc.

TrueLight Commodities, LLC
Trumpet Trading Group, LLC
Trustees of the University of Pennsylvania, a Pennsylvania Non-Profit Corporation d/b/a
University of Pennsylvania, The
Twin Cities Energy, LLC
Twin Cities Power, LLC
Twin Eagle Resource Management, LLC
UGI Development Company
UGI Energy Services, Inc.
UGI Utilities, Inc.
Union Electric Company d/b/a Ameren Missouri
Union Power Partners, L.P.
University Park Energy, LLC
U.S. Energy Partners dba PAETEC Energy
U.S. Energy Services, Inc.
UtiliTech, Inc.
Utility Advantage, LLC
Valero Power Marketing, LLC
VCharge, Inc.
Velocity American Energy Master I, LP
Vel Energy, LLC
Verde Energy USA, Inc.
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verisae, Inc.
Vette Energy, LLC
Vineland Municipal Electric Utility
Viridian Energy PA, LLC
Viridity Energy, Inc.
Virginia Division of Consumer Counsel
Virginia Electric and Power Company
Virginia State Corporation Commission
Vision Power, LLC
Vitol, Inc.
Vlast LLC
VMAC LLC
Wabash Valley Power Association, Inc.
Washington Gas Energy Services, Inc.
Webenergy.net, Inc. d/b/a Consumer Powerline
Wellsboro Electric Company
Wells Fargo Commodities, LLCWestar Energy, Inc.
West Deptford Energy, LLC
West Deptford Energy II, LLCWest Oaks Energy LP
West Penn Power Company d/b/a/ Allegheny Power
West Virginia Consumer Advocate Division

Western Reserve Energy Services, LLC
Wheelabrator Frackville Energy Co Inc.
Wheelabrator Portsmouth, Inc.
Wheeling Power Company
Wildcat Wind Farm I, LLC
Windy Bay Power LLC
Wisconsin Electric Power Company
Wisconsin Power and Light Company
Wisconsin Public Power, Inc.
Wolf Hills Energy, LLC
Wolverine Power Supply Cooperative, Inc.
Wolverine Trading, LLC
Woodway Energy Partners, LLC
WPS Westwood Generation, LLC
XO Energy CAL2 LP
XO Energy MA, LP
XO Energy MA2, LP
XO Energy NY2 LP
Xoom Energy, LLC
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
York Generation Company LLC
Your Energy Holdings, LLC
Zacho Energy Trading, LLC.
Zongyi Solar America Co. Ltd.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
RAA Schedule 10 Sec 1, RAA Schedule 10 Sec 1 - Locational Deliverability Areas and, 7.0.0, A
Record Narative Name: RAA SCHEDULE 10.1- LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS
Tariff Record ID: 295
Tariff Record Collation Value: 979976007   Tariff Record Parent Identifier: 205
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

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:

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

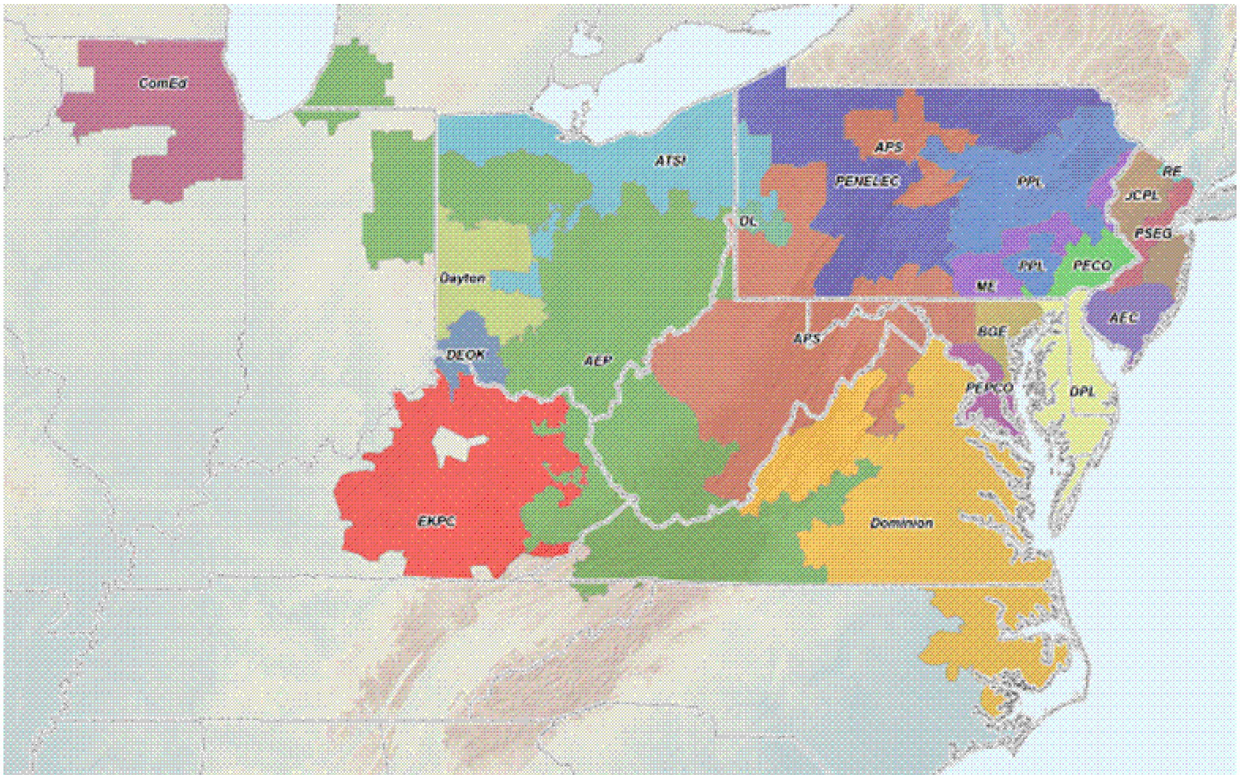
The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into PJM prior to the commencement 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.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
RAA SCHEDULE 15, RAA SCHEDULE 15, 4.0.0, A
Record Narative Name: RAA SCHEDULE 15 - ZONES WITHIN THE PJM REGION
Tariff Record ID: 298
Tariff Record Collation Value: 983551522 Tariff Record Parent Identifier: 205
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

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
East Kentucky Power Cooperative, Inc.	EKPC

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
RAA SCHEDULE 17, RAA SCHEDULE 17, 13.0.0, A
Record Narative Name: SCHEDULE 17 - PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

Tariff Record ID: 278
Tariff Record Collation Value: 984981728   Tariff Record Parent Identifier: 205
Proposed Date: 2013-06-01
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Energy, Inc.
AEP Retail Energy Partners LLC
Agway Energy Services, 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
    Indiana Michigan Power Company
    Kentucky Power Company
    Kingsport Power Company
    Ohio Power Company
    Wheeling Power Company.
American Illuminating Company, LLC
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
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.
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
Choice Energy, LLC dba 4 Choice 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.
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
Eagle Energy, LLC
East Kentucky Power Cooperative, Inc.
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.me Midwest llc d/b/a energy.me
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
Iron Energy LLC
J. Aron & Company
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jersey Central Power & Light Company
Keil and Sons, Inc. dba Systrum Energy
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
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.
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 DC, LLC
Palmco Power IL, LLC
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
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
Red Oak Power, 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
Titan Gas and Power
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
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, 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

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