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July 13, 2011

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: PJM Interconnection, L.L.C., Docket No. ER11-4040-000

Dear Ms. Bose:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, PJM Interconnection, L.L.C. ("PJM") hereby submits to the Federal Energy Regulatory Commission ("Commission") non-substantive, ministerial and/or technological revisions to correct the PJM Open Access Transmission Tariff ("OATT"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.[1] ("OA"), and the Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA")[2]. PJM requests an effective date July 14, 2011, for the proposed OATT, OA and RAA revisions.

I. Background

PJM received a call from Commission Staff informing PJM of issues that occurred with the software technology causing various sections of the PJM OATT, OA and RAA to render out of order in the Commission's eTariff Viewer. Additionally, PJM

[1] PJM Rate Schedule No. 24
[2] PJM Rate Schedule No. 44

recently performed a review of the PJM OATT, OA and RAA to ensure the PJM baseline filing submitted to the Commission September 17, 2010[3], per Order 714[4] and subsequent eTariff filings have been properly formatted and all filed and accepted revisions were accurately captured in the electronic tariff documents. PJM submits this filing to correct the following errors in the PJM OATT, OA and RAA pursuant to the advice from Commission Staff:

i) changes that were previously accepted by the Commission but not reflected in PJM electronic baseline filings initially submitted on September 17, 2010, or which were overwritten due to overlapping filing dates and effective dates or simply omitted due to administrative error as identified more fully in the chart marked as Attachment A to this transmittal letter;

ii) non-substantive typographical corrections, removal of complicated styles, i.e., paragraph styles; clarification of the titles of various sections in the OATT, OA and RAA, and removal of the title "Intra-PJM Tariff" from the header of certain sections identified in Attachment A;

iii) changes to correct the proper parent-child relationship coding to restore the tariff sections to their proper location (i.e., re-map the sections) as identified in Attachment A;

iv) changes to clarify the titles of various sections in the electronic tariff software by submitting non-substantive revisions to the metadata in the Section Title and Section Description, specifically related to the OATT Attachment GG and its Appendices to ensure that the sections are labeled properly as identified in Attachment A; and

[3] PJM submitted errata filings to the September 17 Baseline Tariffs Filing on September 23, 2010, September 27, 2010, October 14, 2010, October 21, 2010, November 17, 2010, and November 26, 2010.
[4] *Electronic Tariff Filings*, Order No. 714, III FERC Stats. & Regs. ¶ 31,276 (2008) ("Order No. 714").

v) changes to correct errors in the table of contents for the OATT, OA and RAA.

II. Description of OATT, OA and RAA Revisions

The chart attached hereto as Attachment A describes revisions to the OATT, OA and RAA which were previously approved by the Commission in prior filings, represent ministerial formatting errors, or technical corrections related to the parent-child relationship coding errors described above.

III. EFFECTIVE DATE AND WAIVER REQUEST

With regard to the OATT, OA and RAA revisions mentioned above, PJM requests an effective date July 14, 2011. To permit such effective dates, PJM requests a waiver of the 60-days' notice requirement in section 35.3(a)(1) of the Commission's regulations, 18 C.F.R.§ 35.3(a)(1); however, PJM does not request an expedited review by Commission Staff. Good cause exists for such waiver because the amendments filed herein only incorporate language previously accepted by the Commission, correct ministerial formatting changes, and/or correct the electronic tariff software coding (i.e. mapping) errors.

IV. DOCUMENTS ENCLOSED

PJM encloses with this errata transmittal letter:

- The OATT, OA and RAA sections in RTF format; and
- Attachment A – Chart describing type of changes to the OATT, OA and RAA;
- Attachment B – A redline version of the revised sections to OATT, OA and RAA (excluding those changes which are technical only, have no textual revisions and submitted in "rtf" format only); and
- Attachment C – A clean version of the revised sections to the OATT, OA and RAA.

V. CORRESPONDENCE AND COMMUNICATIONS

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VI. SERVICE

PJM has served a copy of this filing on all 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,[5] 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[6] alerting them that this filing has been made by PJM and is available by following such link. 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 FERC's eLibrary website located at the following link:

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

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

http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

Respectfully submitted,

/s/ Steven R. Pincus

Steven R. Pincus
PJM Interconnection, L.L.C.

Attachment A

Chart showing Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
PJM Tariff							
1.	OATT Table of Contents	1424	7/14/2011	3.0.0	500	Correct formatting errors, remove the "Intra-PJM Agreements" from the header, and insert missing title from recently approved filings.	NA
2.	OATT 3 Ancillary Services	15	7/14/2011	2.0.0	500	Correct the spelling of the word "participants".	Remap to correct Parent-Child relationship
3.	3.1, OATT 3.1 Scheduling, System Control and Dispatch Services	51	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
4.	3.2, OATT 3.2 Reactive Supply and Voltage Control from Generation	52	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
5.	3.3, OATT 3.3 Regulation and Frequency Response Service	53	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
6.	3.4, OATT 3.4 Energy Imbalance Service:	54	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
7.	3.5, OATT 3.5 Operating Reserve - Synchronized Reserve Service	55	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
8.	3.6, OATT 3.6 Operating Reserve - Supplemental Reserve Service	56	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
9.	3D, OATT 3D Transitional Market Expansion Charge	18	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
10.	7, OATT 7 Billing and Payment	24	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
11.	7.1, OATT 7.1 Billing Procedure	61	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
12.	7.1A, OATT 7.1A Payments	62	7/14/2011	3.0.0	500	Correct typo in section (f) adding an "a" to "as".	Remap to correct Parent-Child relationship
13.	7.2, OATT 7.2 Interest on Unpaid Balances	63	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
14.	7.3, OATT 7.3 Customer Default	64	7/14/2011	2.0.0	500	Remove page number in footer.	Remap to correct Parent-Child relationship

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
15.	OATT 23.1 Procedures for Assignment or Transfer of Service	129	7/14/2011	2.0.0	500	Correct spacing in "PJMSettlementor".	NA
16.	OATT 29.1 Condition Precedent for Receiving Service	145	7/14/2011	1.0.0	500	Section 29.1 Re-insert missing language previously approved by FERC in the First Revised Original Sheet No. 80 in Docket No. RT01-2-006 on March 20, 2003. The language was lost while submitting a squeeze sheet in Docket No. ER07-20-000. PJM's electronic baseline filing did not include the missing language. The missing language is shown in red: "and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement."	NA
17.	OATT SCHEDULE 10-NERC	525	7/14/2011	3.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
18.	OATT SCHEDULE 16-A Transmission Service Imports - Linden VFT	1527	7/14/2011	1.0.0	500	Corrected complicated paragraph styles and page number formatting.	NA
19.	OATT Attachment A-1	537	7/14/2011	2.0.0	500	Correct formatting size in signature block.	NA
20.	OATT Attachment C	539	7/14/2011	2.0.0	500	Correct spacing and typos in Exhibit 1: "counteflows" should be "counterflows"; "an including" should be "and including"; "Paralles" should be "Parallels"; and "indentified" should be "identified".	NA
21.	OATT Attachment F-1	544	7/14/2011	2.0.0	500	Correct bold formatting in signature block.	NA
22.	OATT Attachment K, B2 Determination of Credit	556	7/14/2011	1.0.0	500	Correct formatting by removing extra spacing.	NA

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
23.	OATT Attachment K Section C. Offset of Transmission Congestion	557	7/14/2011	2.0.0	500	Replace the missing "C" in "Paragraph C" not carried forward in PJM's baseline filing.	NA
24.	OATT Attachment K Section 1.6A PJMSettlement	1503	7/14/2011	1.0.0	500	Corrected formatting and title in metadata.	NA
25.	OATT Attachment M-2 (PSE&G) Procedures for Load Determination	949	7/14/2011	1.0.0	500	Insert "Attachment M-2 (PSE&G)" in the title.	Clarify title in Metadata to include "OATT ATTACHMENT M2 (PSE&G)"
26.	OATT Attachment M-2 (Atlantic City Electric Company) Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers	950	7/14/2011	1.0.0	500	Insert "Attachment M-2" in the title.	Clarify title in Metadata to include "OATT ATTACHMENT M2 (Atlantic City Electric Company)"
27.	OATT Attachment M-2 (Delmarva Power & Light Company) Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers	951	7/14/2011	1.0.0	500	Insert "Attachment M-2" in the title.	Clarify title in Metadata to include "OATT ATTACHMENT M2 (Delmarva)"
28.	OATT Attachment M-2 (Delmarva Power & Light Company) Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers	952	7/14/2011	1.0.0	500	Insert "Attachment M-2" in the title.	Clarify title in Metadata to include "OATT ATTACHMENT M2 (Delmarva)"
29.	OATT Attachment DD.2	1139	7/14/2011	6.0.0	500	Correct tab formatting to Definition 2.65.	NA
30.	OATT ATTACHMENT DD.3. RESPONSIBILITIES OF THE OFFICE OF THE	1140	7/14/2011	3.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
31.	OATT ATTACHMENT DD.5.3A Locational UCAP Bilateral Transactio	1146	7/14/2011	1.0.0	500	Remove extra line space from between "Locational UCAP" and "Seller".	NA

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
32.	OATT ATTACHMENT DD.5.4 Reliability Pricing Model Auctions	1147	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
33.	OATT Attachment DD 5.6	1149	7/14/2011	4.0.0	500	Insert space between "installedcapacity".	NA
34.	OATT ATTACHMENT DD.5.7 Buy Bids,	1150	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
35.	OATT ATTACHMENT DD.5.8 Submission of Sell Offers and Buy Bid	1151	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship
36.	OATT ATTACHMENT DD.5.10 Auction Clearing Requirements	1153	7/14/2011	4.0.0	500	Reinsert language in the OATT Attachment 5.10(a)(v)(B) which was erroneously omitted from PJM's electronic baseline filing in Docket No. ER10-2710-000. The missing language is shown in red: "B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Market 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; …".	Remap to correct Parent-Child relationship
37.	OATT ATTACHMENT DD.5.11 Posting of Information Relevant	1154	7/14/2011	3.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
38.	OATT ATTACHMENT DD.6	1161	7/14/2011	4.0.0	500	Section 6.6(c) Re-insert language previously approved in Docket No. ER11-2527-000 by Order dated February 9, 2011. The language was lost when filing revisions in Docket No. ER11-2287 approved on January 31, 2011 (134 FERC ¶ 61,065). The missing language is shown in red: "(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below and section II.CE of Attachment M - Appendix." Section 6.6(g) Correct the spacing in the following: "resourcein" and "Auction.However"; and Section 6.6(i) Correct the spacing above the subparagraph "(h)".	NA
39.	OATT ATTACHMENT DD.8. CAPACITY RESOURCE DEFICIENCY CHARGE	1163	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship.
40.	OATT ATTACHMENT DD.9. PEAK SEASON MAINTENANCE COMPLIANCE PEN	1164	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship.

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
41.	OATT ATTACHMENT DD-1	1174	7/14/2011	2.0.1	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship. PJM is providing a squeeze section, Version 2.0.1, with the language approved in Docket No. ER11-2288-000. Pending Version 3.0.0 will not become effective until November 7, 2011 under Docket No. ER11-3322.
42.	OATT ATTACHMENT GG. FORM OF UPGRADE CONSTRUCTION SERVICE AGREEMENT	1135	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
43.	OATT ATTACHMENT GG, APPENDIX I SCOPE AND SCHEDULE OF WORK FOR DIRECT ASSIGNMENT FACILITIES OR CUSTOMER-FUNDED UPGRADES TO BE BUILT BY TRANSMISSION OWNER	1136	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
44.	OATT ATTACHMENT GG, APPENDIX II. DEFINITIONS	1137	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
45.	OATT ATTACHMENT GG, APPENDIX III, GENERAL TERMS AND CONDITIONS	1175	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
46.	OATT ATTACHMENT GG, APPENDIX III.1.0 Effective Date and Term	1176	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
47.	OATT ATTACHMENT GG, APPENDIX III.2.0 Facilitation by Transmission Provider	1177	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
48.	OATT ATTACHMENT GG, APPENDIX III.3.0 Construction Obligations	1178	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
49.	OATT ATTACHMENT GG, APPENDIX III.4.0 Tax Liability	1179	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
50.	OATT ATTACHMENT GG, APPENDIX III.5.0 Safety	1180	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
51.	OATT ATTACHMENT GG, APPENDIX III.6.0 Schedule Of Work	1181	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
52.	OATT ATTACHMENT GG, APPENDIX III.7.0 Suspension of Work Upon Default	1182	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
53.	OATT ATTACHMENT GG, APPENDIX III.8.0 Transmission Outages	1183	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
54.	OATT ATTACHMENT GG, APPENDIX III.9.0 Security, Billing And Payments	1184	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
55.	OATT ATTACHMENT GG, APPENDIX III.10.0 Assignment	1185	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
56.	OATT ATTACHMENT GG, APPENDIX III.11.0 Insurance	1186	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
57.	OATT ATTACHMENT GG, APPENDIX III.12.0 Indemnity	1187	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
58.	OATT ATTACHMENT GG, APPENDIX III.13.0 Breach, Cure And Default	1188	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
59.	OATT ATTACHMENT GG, APPENDIX III.14.0 Termination,	1189	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
60.	OATT ATTACHMENT GG, APPENDIX III.15.0 Force Majeure	1190	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
61.	OATT ATTACHMENT GG, APPENDIX III.16.0 Confidentiality	1191	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
62.	OATT ATTACHMENT GG, APPENDIX III.17.0 Information Access And Audit Rights	1192	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
63.	OATT ATTACHMENT GG, APPENDIX III.18.0 Representations and Warranties	1193	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
64.	OATT ATTACHMENT GG, APPENDIX III 19.0 Inspection and Testing of Completed Facilities	1194	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
65.	OATT ATTACHMENT GG, APPENDIX III.20.0 Energization of Completed Facilities	1195	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
66.	OATT ATTACHMENT GG, APPENDIX III.21.0 Transmission Owner's Acceptance of Fa,	1196	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
67.	OATT ATTACHMENT GG, APPENDIX III.22.0 Transfer of Title to Certain Faciliti,	1197	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
68.	OATT ATTACHMENT GG, APPENDIX III.23.0 Liens	1198	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "OATT ATTACHMENT GG".
69.	OATT ATTACHMENT HH	1492	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to proper location.
70.	OATT ATTACHMENT II	1526	7/14/2011	1.0.0	500	Remove complicated styles/formatting.	Remap to proper location.

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
PJM Operating Agreement							
71.	OA Title Page	633	7/14/2011	1.0.0	500	Insert the missing language "Rate Schedule FERC No. 24" to the OA cover page and correct the line formatting.	Separate and Map the OA Title Page, Resolution Page and TOC in their proper locations.
72.	OA Resolution and Certification Page.	1529	7/14/2011	0.0.0	500	No textual revisions; submitted in 'rtf' format only.	Separate and Map the OA Title Page, Resolution Page and TOC in their proper locations.
73.	OA Table of Contents	1481	7/14/2011	2.0.0	500	Correct formatting issues with lines showing across the words "Table of Contents" and remove extra line spacing to be consistent.	Separate and Map the OA Title Page, Resolution Page and TOC in their proper locations.
74.	OA Schedule 1, Section 5.5 Distribution of Total Transmission Loss Charges	797	7/14/2011	4.0.0	500	Remove "Intra-PJM Tariff" header from the section. Re-insert language previously approved by FERC in Docket Nos. ER11-1987-000 and ER11-1988-000 by Letter Orders dated 12/30/2011. The missing language is shown in red: "The total Transmission Loss Charges accumulated by ~~the Office of the Interconnection~~ PJMSettlement in any hour shall be distributed pro-rata to each Network Service User...".	NA
PJM Reliability Assurance Agreement							
75.	RAA Article 1- Definitions	206	7/14/2011	3.0.0	500	Replace the bold formatting for the Definitions 1.1A, 1.20C and 1.43A; remove italics from pending language due to overlapping filings in Docket Nos. ER11-2287-000 and ER11-2288-000 and approved by Letter Orders dated January 31, 2011.	NA

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
76.	RAA SCHEDULE 6	277	7/14/2011	2.0.1	500	Re-insert missing language in Paragraph M.1 which was previously approved by FERC in Docket No. ER11-1909-000 by Order dated 12/20/2010. The language was lost due to overlapping filings. The missing language is shown in red: "An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described herein) reduction in electric energy consumption at the End-Use Customer's Retail Site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention."	NA
77.	RAA SCHEDULE 8.1	281	7/14/2011	1.0.0	500	Capitalize the words "Fixed Resource" to reflect properly in the title.	NA
78.	RAA SCHEDULE 8.1.A, The Fixed Resource Requirement ("FRR") Alternative	282	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "RAA SCHEDULE 8.1".
79.	RAA SCHEDULE 8.1.B, Eligibility	283	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "RAA SCHEDULE 8.1".
80.	RAA SCHEDULE 8.1.C, Election, and Termination of Election, of FRR Alterna	284	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "RAA SCHEDULE 8.1".

Non-Substantive, Ministerial and Technological Corrections to the PJM Tariff, OA & RAA							
No.	PJM Section Title	Record ID	Proposed Effective Date	Version	Priority Code	Textual & Formatting Revision	Technological Revision
81.	SCHEDULE 8.1.D, FRR Capacity Plans	285	7/14/2011	3.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship. Clarify title in Metadata to include "RAA SCHEDULE 8.1".
82.	RAA SCHEDULE 8.1.E, Conditions on Purchases and Sales of Capacity Resourc	286	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "RAA SCHEDULE 8.1".
83.	RAA SCHEDULE 8.1.F, FRR Daily Unforced Capacity Obligations and Deficienc	287	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "RAA SCHEDULE 8.1".
84.	SCHEDULE 8.1.G, Capacity Resource Performance	288	7/14/2011	2.0.0	500	No textual revisions; submitted in 'rtf' format only.	Remap to correct Parent-Child relationship. Clarify title in Metadata to include "RAA SCHEDULE 8.1".
85.	RAA SCHEDULE 8.1.H, Annexation of service territory by Public Power Entit	289	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "RAA SCHEDULE 8.1".
86.	RAA SCHEDULE 8.1.I, Savings Clause for State-Wide FRR Program	290	7/14/2011	1.0.0	500	No textual revisions; submitted in 'rtf' format only.	Clarify title in Metadata to include "RAA SCHEDULE 8.1".

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3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Synchronized, and (iv) Operating Reserve - Supplemental. Subject to the provisions of Schedules 1 through 6, the Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Provider shall administer the purchases by Transmission Customers of these Ancillary Services. PJMSettlement shall be the Counterparty to the Ancillary Services provided to the Transmission Customer; provided, however, that PJMSettlement shall not be the contracting party to bilateral transactions between market par~~i~~tic<u>ip</u>ants or with respect to a self-schedule or self-supply relating to Ancillary Services. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible. The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Service provided by the Transmission Provider in conjunction with its

provision of transmission services 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. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

7.1A Payments:

(a) Monthly Bills.

Net amounts due to PJMSettlement, in its own name or as agent for Transmission Provider, as applicable, pursuant to a monthly bill shall be due and payable by the Transmission Customer or other entity no later than noon Eastern Prevailing Time on the due date of the first weekly bill issued for activity in the month that the monthly bill is issued. It is possible, due to the timing of holidays, that the billing and payment cycle for monthly bills stated here would call for payment of a monthly bill on a Friday that occurs less than three business days after issuance of the bill by PJM. Where this occurs, the payment period of the monthly bill will be extended such that payment will be due when payment for the second weekly bill is due.

(b) Weekly Bills.

Net amounts due to PJMSettlement, in its own name or as agent for Transmission Provider, as applicable, pursuant to a weekly bill shall be due and payable by the Transmission Customer or other entity no later than noon Eastern Prevailing Time on the third business day following the issuance of the weekly bill. Weekly bills issued after 5:00 p.m. Eastern Prevailing Time shall be considered to be issued the following business day

(i) Municipal Electric Systems.

Recognizing that municipal electric systems may, at times, face unique circumstances that could temporarily prevent their ability to make payments on a weekly bill issued pursuant to Section 7.1(b) when due, the Transmission Provider may allow a municipal electric system to make arrangement with PJM whereby PJM would extend trade credit to the municipal electric system sufficient to enable it to make payment on a weekly bill provided that the following conditions are met:

(a) the Transmission Provider determines, in its sole discretion, that it has sufficient excess working capital available to complete financial settlement with other market participants;

(b) the municipal electric system reimburses PJM for the actual cost of such working capital;

(c) the municipal electric system provides PJM with a binding representation that it has all legal right and authority to enter into the arrangement with PJM;

(d) PJMSettlement will continue to issue weekly bills to the municipal electric system in accordance with Section 7,1(b) above and the municipal electric system will make payment as due under the weekly bills using the proceeds it obtains

under its arrangement with PJM. Reimbursement of these amounts, including PJM's actual costs of working capital, shall be due from the municipal electric system at the time payment is due for the invoice issued under Section 7.1A(a);

(e) the aggregate of all financed amounts and accrued obligations shall not exceed the Working Credit Limit available to the municipal electric system;

(f) the municipal electric system provides the Transmission Provider with at least one week of notice (though PJM may waive this provision), and;

(g) the accumulated duration of such postponed payments shall not exceed three months in a rolling twelve-month period.

PJM may terminate this payment option at any time it determines its excess working capital is no longer sufficient to allow further or continued extension financing. In such cases, PJM shall attempt to give five business days, but not less than three business days notice to the affected municipal electric system, and may call for immediate reimbursement of any outstanding amounts owed by the municipal electric system.

(c) Form of Payments.

All payments tendered in satisfaction of a Transmission Customer's or other entity's obligations to PJMSettlement or Transmission Provider shall be in the form of immediately available funds payable to PJMSettlement, or by wire transfer to a bank named by PJMSettlement.

(d) Payments by PJMSettlement.

Unless delayed by unforeseen events, payments made by PJMSettlement, in its own name or as agent for Transmission Provider, for amounts due to Transmission Customers and other entities shall be paid no later than 5:00 p.m. Eastern Prevailing Time on the business day following the payment due date for net amounts owed to PJMSettlement, in its own name or as agent for the Transmission Provider, as specified above.

(e) Payment Calendar.

A comprehensive billing and settlement calendar will be posted on Transmission Provider's website prior to March 31 for the upcoming June – May annual period to communicate the schedule of holidays for settlement and billing purposes.

(f) Late Payments.

In the event that a Transmission Customer, or other entity, is delinquent in paying the amount set forth in its weekly or monthly bill two or more times within any rolling twelve (12) month period, PJMSettlement, in its own name or as agent for Transmission Provider, may assess, in addition to the interest on each late payment as provided for in

Section 7.2 of this Tariff, a late payment charge for a second and any subsequent failure to pay on time during such twelve (12) month period (a "Late Payment Charge"). The applicable Late Payment Charge will be assessed in an amount equal to the greater of: (i) two percent (2%) of the total amount set forth in the monthly or weekly bill that the Transmission Customer or other entity has been late in paying, or (ii) $1,000; up to a maximum of $100,000 per late bill payment. For the sole purpose of application of this Section 7.1A(f), weekly and monthly bills that are due on the same date shall be considered to be one bill; moreover, the term "on time" shall mean payment received on the date due; and "delinquent" shall mean any payment received on a day subsequent to the date due.

Late Payment Charges that are collected pursuant to this Section 7.1A(f) shall be credited to PJMSettlement administrative costs and will be included in any applicable stated rate refund calculations as contemplated under Schedule 9 of this Tariff.

23.1 Procedures for Assignment or Transfer of Service:

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion; provided that, for service prior to October 1, 2010, compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Transmission Provider and PJMSettlement governing reassignments of transmission service prior to the date on which the reassigned service commences. PJMSettlement shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider and PJMSettlement or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider and PJMSettlement or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

29.1 Condition Precedent for Receiving Service:

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff or, with respect to a state required retail access program, provides the information required under the Service Agreement, (ii) the Eligible Customer and the Transmission Provider in coordination with the affected Transmission Owners complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F or Attachment F-1 for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

SCHEDULE 16-A

Transmission Service for Imports on the Linden VFT Facility

Pursuant to Section 38 of the Tariff, this Schedule provides the terms and conditions of transmission service for imports on the Linden VFT Facility which is a Merchant Transmission Facility under the Tariff and the Amended and Restated Operating Agreement of PJM Interconnection, L.LC ("Operating Agreement").

1. Definitions

Capitalized terms used and defined in this Schedule 16-A shall have the meaning given them under this Schedule. Capitalized terms used and not defined in this Schedule 16-A but defined in other provisions of the Tariff shall have the meaning given them under those provisions. Capitalized terms used in this Schedule 16-A that are not defined in it or elsewhere in this Tariff shall have the meanings customarily attributed to such terms by the electric utility industry in PJM, including, but not limited to the Operating Agreement.

1.1 Linden VFT Reservation: For purposes of this Schedule 16-A, a right, denoted in whole megawatts and for a specified period, to request the injection of energy and capacity into the Transmission System at the Point of Interconnection and submit schedules for transmission service utilizing the Linden VFT Facility on a firm or non-firm basis as set forth in this Schedule 16-A.

1.1.1 Firm Linden VFT Reservation: A Firm Linden VFT Reservation allows a Linden VFT Transmission Customer to schedule capacity and energy on a firm basis from the Linden VFT Point of Receipt to the Linden VFT Point of Delivery.

1.1.2 Non-Firm Linden VFT Reservation: A Non-Firm Linden VFT Reservation allows a Linden VFT Transmission Customer to schedule energy on a non-firm, as available, basis from the Linden VFT Point of Receipt to the Linden VFT Point of Delivery.

1.2 Linden VFT Transmission Customer: An entity that (i) is an Eligible Customer (or its Designated Agent) that meets the creditworthiness requirements of the Transmission Provider set forth in Attachment Q to this Tariff and is in good-standing with respect to all payments owed under the Tariff and Operating Agreement; (ii) executes a Linden VFT Service Agreement, the form of which is attached as Exhibit A to this Schedule 16-A; (iii) holds a Linden VFT Reservation, and, in the case of a re-sale of a Linden VFT Reservation, (iv) has the applicable Attachment A-1 completed and signed by all parties.

1.3 Linden VFT Facility: The Linden VFT Facility is a controllable alternating current Merchant Transmission Facility located in Linden, New Jersey, which was the subject of Commission orders in FERC Docket No. ER07-543 et al. regarding operation of these transmission facilities as a merchant transmission facility and as more particularly described in the Interconnection Service Agreement among PJM Interconnection, L.L.C. and Linden VFT,

LLC and Public Service Electric and Gas Company, which was accepted for filing by the Commission in FERC Docket No. ER06-649.

1.4 Linden VFT Schedule: The schedule for the transmission of capacity and energy on the Linden VFT Facility pursuant to the terms and conditions of service set forth in this Schedule 16-A.

1.4A Linden VFT Service: Transmission service provided pursuant to the terms and conditions of service set forth in this Schedule 16-A.

1.5 Linden VFT Transmission Owner: Linden VFT, LLC, its agents, successors or assigns.

1.6 Primary Rights Holder(s): Entities that have been allocated rights to the use of the transmission capability of the Linden VFT Facility and assigned Firm and Non-Firm Transmission Injection Rights by the Linden VFT Transmission Owner in accordance with Section 2.1. To the extent any portion of the total transmission capability of the Linden VFT Facility has not been assigned pursuant to Section 2.1 the Linden VFT Transmission Owner shall be the Primary Rights Holder of such capacity for purposes of this Schedule 16-A until such capacity is allocated to another entity.

1.7 Point of Interconnection: The Point of Interconnection is as defined in Section 11.1 of the Interconnection Service Agreement among PJM Interconnection, L.L.C. and East Coast Power, L.L.C., which was assigned to Linden VFT, LLC effective December 21, 2006, and is the Linden VFT Point of Delivery.

1.8 Linden VFT Service Agreement: An initial agreement and any amendments or supplements thereto entered into by a Linden VFT Transmission Customer and the Transmission Provider for transmission service on the Linden VFT Facility under this Schedule 16-A, the form of which is included as Exhibit A to this Schedule 16-A.

1.9 Linden VFT Point of Delivery: For purposes of this Schedule 16-A, the point of delivery is the Point of Interconnection with the 230 kV transmission line connecting Public Service Electric and Gas Company's Warinanco substation with the Tosco substation near Linden, New Jersey.

1.10 Linden VFT Point of Receipt: For purposes of this Schedule 16-A, the point of receipt is the point of connection with transmission facilities at the 345 kV Linden Cogen ring bus, which is the point for the interchange of capacity and energy between PJM and NYISO.

2. Allocation of Available Transmission Capability on the Linden VFT Facility

2.1 Commission Approved Allocation Process: The Linden VFT Transmission Owner shall allocate the total transmission capability on the Linden VFT Facility pursuant to an allocation process approved by the Commission under FERC Docket No. ER07-543-000 as such allocation process may be amended by the Linden Transmission Owner from time-to-time

subject to Commission approval provided that the results of such rights allocation process shall be furnished to the Transmission Provider and posted on the OASIS. The allocation of rights to Primary Rights Holders for the transmission capability of the Linden VFT Facility shall include the allocation of the Firm and Non-Firm Transmission Injection Rights, as applicable, which have been assigned to the Linden VFT Transmission Owner pursuant to Section 232 of this Tariff as well as the award of Firm and Non-Firm Linden VFT Reservations. The allocation of such rights shall be in the megawatt quantity and for the period specified for allocation to parties pursuant to the Linden VFT Transmission Owner's Commission-approved allocation process and as submitted to the Transmission Provider for posting on the OASIS. In the event that there has been no allocation of Firm or Non-Firm Transmission Injection Rights to a Primary Rights Holder, the Linden VFT Transmission Owner is the holder of such unallocated Firm or Non-Firm Transmission Injection Rights.

2.2 Charges for Allocation of Rights by Linden VFT Transmission Owner to Primary Rights Holder: The charges applicable to the allocation of rights to a Primary Rights Holder pursuant to this section shall be determined pursuant to arrangements between the Linden VFT Transmission Owner and the Primary Rights Holder in accordance with the process approved by the Commission under FERC Docket No. ER07-543-000, as amended by the Linden VFT Transmission Owner from time-to-time subject to Commission approval. The charge for the allocation of rights to a Primary Rights Holder shall be in accordance with the Commission's authorization for the Linden VFT Transmission Owner to charge negotiated rates (i.e., rates established pursuant to market mechanisms as recognized for merchant transmission projects and not included in Transmission Provider's Tariff rates) for the use of transmission capability over the Linden VFT Facility. Agreements between the Linden VFT Transmission Owner and a Primary Rights Holder for the allocation of rights to a Primary Rights Holder shall be considered Service Agreements under this Schedule 16-A and shall be reported by the Linden VFT Transmission Owner to the Commission through Electronic Quarterly Reports in accordance with Order No. 2001.

2.3 Transmission Injection Rights Associated with the Linden VFT Facility: The award of Transmission Injection Rights to the Linden VFT Transmission Owner shall be made pursuant to Section 232 of the Tariff and any subsequent transfer to Primary Rights Holders shall be made in accordance with Section 2.1 hereof. The Transmission Injection Rights solely allow for the injection of capacity and energy at the Point of Interconnection for the Linden VFT Facility and do not provide any priority with respect to the reservation, scheduling, curtailment or interruption of transmission service over the Linden VFT Facility pursuant to this Schedule.

2.4 Transfer of Transmission Injection Rights: Any resale, assignment, conveyance or transfer of a Transmission Injection Right shall be consistent with Section 232.6 of this Tariff and any terms and conditions agreed upon between the Linden VFT Transmission Owner and the Primary Rights Holder.

3. Linden VFT Reservations

3.1 Effect of a Linden VFT Reservation: A Linden VFT Reservation is a prerequisite to scheduling capacity and/or energy on the Linden VFT Facility. A holder of a

confirmed Linden VFT Reservation may submit offers to schedule capacity and/or energy into the Transmission System at the Point of Interconnection over the Linden VFT Facility.

3.2 Recallability: A Non-Firm Linden VFT Reservation released pursuant to Section 3.7 is recallable by a holder of a Firm Linden VFT Reservation that has retained the right of recall until the deadline posted on the OASIS which shall be based on the time necessary for submittal of energy bids to meet installed capacity obligations in PJM. The procedures and prerequisites for the exercise of recall rights are set forth in Section 4.2.2.

3.3 Term of Service

3.3.1 Firm Linden VFT Reservation: The minimum term of a Firm Linden VFT Reservation shall be one day and the maximum term shall be equal to the term of agreement allocating rights to the Primary Rights Holder, the capability of the Linden VFT Facility pursuant to Section 2.1 of this Schedule. The terms and conditions applicable to Firm Point-To-Point Transmission Service in Part II of the Tariff shall apply to any and all Firm Linden VFT Reservations.

3.3.2 Non-Firm Linden VFT Reservation: The terms and conditions of Non-Firm Point-To-Point Transmission Service in Part II of the Tariff shall apply to any and all Non-Firm Linden VFT Reservations.

3.3.3 Limitations. A Linden VFT Transmission Customer holding a Firm Linden VFT Reservation or Non-Firm Linden VFT Reservation may not submit a request for scheduling of capacity and energy over the Linden VFT Facility that exceeds the period or megawatt amount of its Linden VFT Reservation.

3.4 Acquisition of Linden VFT Reservations: Linden VFT Reservations are initially allocated to Primary Rights Holders pursuant to Section 2.1 Third parties may purchase Firm Linden VFT Reservation or Non-Firm Linden VFT Reservations through (i) assignment pursuant to Section 3.5 of this schedule or (ii) voluntary or default release through Transmission Provider's resale procedures as stated in the Tariff and the Regional Scheduling Practices in accordance with Section 3.7 of this Schedule. The holder of a Linden VFT Reservation that sells or assigns its rights is hereafter referred to as the Reseller. The entity purchasing a Linden VFT Reservation through resale is hereafter referred to as the Buyer.

3.5 Assignment of Linden VFT Reservation: The Primary Rights Holder of a VFT Reservation may assign its VFT Reservation to third parties in accordance with the terms of the agreement between the Linden VFT Transmission Owner and the Primary Rights Holder provided that notice of such assignment is provided to the Transmission Provider with such information provided on the OASIS. Subject to Commission approval of any necessary filings, a holder of a VFT Reservation may assign all or a portion of its rights, but only to another Eligible Customer (the Buyer). The compensation to the Reseller shall be at rates established by agreement with the Buyer. Notice of such assignment shall be provided to the Transmission Provider as soon as possible after any assignment occurs but in any event, notification must be

provided prior to any submission of offers to schedule capacity and energy pursuant to such VFT Reservation by the Buyer.

3.6 Limitations on Resale of Linden VFT Reservations: If the Buyer requests a change in the specifications set forth in the original Linden VFT Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change is done before the start of service, does not exceed the rights granted in the Reseller's original Linden VFT Reservation and will not impair the operation and reliability of the Linden VFT Facility, the Transmission Provider's Transmission System or a Transmission Owner's generation, transmission, or distribution systems. The Reseller shall remain liable for the performance of all obligations under the Linden VFT Service Agreement, except as specifically agreed to by the Reseller, the Buyer, and the Transmission Provider through an amendment to the Linden VFT Service Agreement. A holder of a Linden VFT Reservation shall notify the Transmission Provider of the resale of any Linden VFT Reservation including the rate to be charged in accordance with the deadlines posted in NAESB WEQ 001-11.5.1.for On-OASIS re-sales, and NAESB WEQ 001-11.5.2 for Off-OASIS re-sales.

3.7 Release of Linden VFT Reservation: Linden VFT Reservations may be resold as Available Transmission Capacity (ATC) for acquisition as Linden VFT Service by third parties using the OASIS. Such a resale of transmission service is subject to the requirements in the PJM Manuals, NERC and NAESB Standards.

3.7.1 Voluntary Releases: A holder of a VFT Reservation may offer all or any portion of its VFT Reservation for voluntarily release on a first-come, first-served basis. A VFT Reservation that has been posted for voluntary release under this subsection shall be excluded from the default release procedures set forth in subsection 3.7.2.

3.7.2 Default Releases: In the event that any holder of a Linden VFT Reservation fails to either: (i) submit a request to schedule energy up to the full MW value of its Linden VFT Reservation by noon (12:00 p.m.) one business day prior to the Operating Day or (ii) offer its VFT Reservation for voluntarily release pursuant to subsection 3.7.1, then, the difference between the Total Transfer Capability over the VFT Line in each scheduling hour of the Operating Day and the sum of the valid requests for Linden VFT Schedules and MW amount of Linden VFT Reservations voluntarily released on OASIS for such scheduling hour, shall be deemed released by the Linden VFT Transmission Owner (as Reseller) and shall be posted on the OASIS by the Transmission Provider as Non-Firm ATC for acquisition by third parties on a first-come, first-served basis.

3.7.3 Release Rate: The holder of a Linden VFT Reservation seeking to voluntarily release all or any portion of its Linden VFT Reservation shall provide to the Transmission Provider the rate to be posted on OASIS and charged for such releases. The Linden VFT Transmission Owner may provide the Transmission Provider a rate to be posted on OASIS and charged for default releases pursuant to Section 3.7.2. In the event that the Linden VFT Transmission Owner does not separately provide to the Transmission Provider a rate for default releases, such default releases shall be charged

the lowest rate posted on OASIS for voluntary release of Linden VFT Reservations in the applicable hour.

3.7.4 Character of Service Released: Releases of Linden VFT Reservations made pursuant to the default release provisions in subsection 3.7.2 do not include the right of recall under Section 3.2 and shall be hourly Non-Firm Linden VFT Reservations.

3.7.5 Requirements for Acquisition of Linden VFT Reservations through Release or Assignment: An Eligible Customer shall be eligible to acquire and hold a Linden VFT Reservation through an assignment of a Linden VFT Reservation pursuant to Section 3.5 or release of a Linden VFT Reservation over OASIS pursuant to Section 3.7 if such entity meets all of the requirements for a Linden VFT Transmission Customer except for part (iii) of such requirements.

3.7.6 Resale Rate: The Reseller of a Linden VFT Reservation shall post the rate on OASIS and will be credited for completed re-sales of its service. The Reseller of a Linden VFT Transmission Reservation and the resale Buyer shall be credited/charged the rate as agreed and posted on the OASIS for the Linden VFT Reservations resold.

3.8 Billing and Payment for Linden VFT Reservations:

3.8.1 Linden VFT Reservations Allocated to Primary Rights Holders Pursuant to Section 2.1: The billing and payment of rates or charges applicable to the allocation of Firm or Non-Firm Linden VFT Reservations to the Primary Rights Holder pursuant to section 2.1 shall be determined pursuant to arrangements between the Linden VFT Transmission Owner and the Primary Rights Holder and not under this Tariff.

3.8.2 Linden VFT Reservations Acquired Through Resale Pursuant to Section 3.7.1: An entity acquiring a Linden VFT Reservation through a Resale over the OASIS pursuant to subsection 3.7.1 shall be billed the applicable rate which is posted on OASIS pursuant to subsection 3.7.3. The Transmission Provider will credit/bill both parties according to the applicable rate and the transaction shall be settled through Transmission Provider's settlements.

3.8.3 Linden VFT Reservations Acquired Through Default Resale: The Transmission Provider shall bill an entity acquiring a Linden VFT Reservation through a default resale the applicable rate which is posted on OASIS pursuant to subsection 3.7.3. Any revenues received from the acquisition of Linden VFT Reservations subject to default release provisions shall be paid by the Transmission Provider to the VFT Transmission Owner. A Linden VFT Transmission Customer shall pay the applicable rates for the megawatt amount of the Linden VFT Reservation for each hour regardless of whether such holder(s) submitted a schedule for transmission service over the Linden VFT Facility in such hour.

4. Linden VFT Schedules

4.1 Nature of Transmission Service over the Linden VFT Facility: Linden VFT Schedules shall be requested in accordance with NERC and NAESB Standards, including requirements relating to E-Tagging and Transmission Line Relief procedures. An entity seeking to schedule use of the Linden VFT Facility must hold a Linden VFT Reservation for no less than the amount of megawatts of service being requested. Deadlines for scheduling the use of the Linden VFT Facility shall adhere to the Transmission Provider's deadlines for scheduling as provided by the Transmission Provider's manuals and consistent with the deadlines for scheduling Point to Point Transmission Services as described in Part II of the Tariff.

4.2 Submission of Scheduling Requests, Award of Reservations, Curtailment and Interruption of Linden VFT Schedule:

4.2.1 Submission of Scheduling Requests: A Linden VFT Transmission Customer holding a Linden VFT Reservation has the right to submit requests for Firm Linden VFT Schedules or Non-Firm Linden VFT Schedules commensurate to the Linden VFT Reservations held by that entity.

4.2.2 Exercise of Recall Rights: An Eligible Customer holding a Firm Linden VFT Reservation, that retains the right of recall, may exercise such recall rights by providing notice, until the deadline posted on the OASIS which shall be based on the time necessary for submittal of energy bids to meet any installed capacity obligations in PJM, to the Transmission Provider that it wishes to exercise its right of recall. The exercise of a recall right pursuant to notice to the Transmission Provider shall immediately act to recall the Linden VFT Reservation previously released by the Eligible Customer and acquired by a third party under the assignment provisions set forth in Section 3.5 or the release procedures set forth in Section 3.7

4.3 Scheduling of Capacity and Energy over the Linden VFT Facility: The Transmission Provider shall evaluate all requests to schedule capacity and energy for injection into the Transmission System at the Point of Interconnection based on economic merit order. In the event of a tie within economic merit, a scheduling request made pursuant to a Firm Linden VFT Reservation shall have priority over a scheduling request made pursuant to a Non-Firm Linden VFT Reservation. In the case of an economic merit order tie between two or more scheduling requests using a Firm Linden VFT Reservation, the award of the scheduling reservation shall be on a pro rata basis. In the case of an economic merit order tie between two or more scheduling requests based on Non-Firm Linden VFT Reservations, the reservation classification of the Non-Firm Linden VFT Reservation (Monthly, Weekly, Daily or Hourly) shall then be used as the tiebreaker, with the longer term of Non-Firm Linden VFT Reservation receiving priority. In the case of a further tie within the sub-category of Non-Firm Linden VFT Reservations (Monthly, Weekly, Daily or Hourly), the timestamp order of the submission of requests to schedule service over the Linden VFT Facility shall be used as a tie-breaker. A holder of Linden VFT Reservations is limited in its total capacity and energy schedule for its Linden VFT Schedule to the higher of either its Firm or Non-Firm Linden VFT Reservations.

4.4 Limitations on Scheduling Amount: The Linden VFT Facility has a minimum total scheduling requirement. of 1 MW at the Linden VFT Point of Receipt. The Linden VFT

Facility has a maximum continuous scheduling capability of the lower of the Total Transfer Capability ("TTC") set by the Transmission Provider or 330 MW at the Linden VFT Point of Delivery. In the event that the total megawatt of schedules determined by the Transmission Provider is greater than the lower of the TTC or 330 MW at the Linden VFT Point of Delivery, all schedules above the maximum capability shall be rejected.

4.5 Curtailment of Linden VFT Schedules: In the event that a Curtailment or interruption of Linden VFT Schedules is required to maintain reliable operation of the Linden VFT Facility and the systems directly and indirectly interconnected with the Linden VFT Facility, any such Curtailment implemented by the Transmission Provider shall be based upon the priority of the associated Linden VFT Reservations. For Curtailment or interruptions of Linden VFT Schedules based on Firm Linden VFT Reservations will be performed on a pro rata basis. Curtailment of Linden VFT Schedules based on Non-Firm Linden VFT Reservations shall first be based on the Non-Firm Linden VFT Reservation classification (i.e., Monthly, Weekly, Daily, Hourly) with the longer term of Non-Firm Linden VFT Reservation receiving priority. In the case of a tie within the Non-Firm Linden VFT Reservation classifications, the time stamp order of the submission of valid bids/offers to schedule service over the Linden VFT Facility shall be used as a tiebreaker. The Transmission Provider shall provide advance notice of any Curtailment of Linden VFT Schedules to all affected Linden VFT Transmission Customers where such notice can be provided consistent with Good Utility Practice. The Transmission Provider shall curtail Linden VFT Schedules over the Linden VFT Facility as required by NERC Standards and the Joint Emergency Operating Protocol for the Linden VFT Scheduled Line which is posted on the PJM website. The Transmission Provider shall curtail Linden VFT Schedules over the Linden VFT Facility for reliability of the Transmission System pursuant to the separately reserved Transmission Service over the Transmission System pursuant to Part II or Part III of the Tariff to the Linden VFT Facility and the Transmission Provider's Manuals.

4.6 Transmission Service Over the Transmission System. Prior to the commencement of a Linden VFT Schedule under this Schedule 16-A, a Linden VFT Transmission Customer shall arrange such Transmission Service over the Transmission System pursuant to Part II or Part III of the Tariff as may be necessary pursuant to the Tariff for delivery of energy, capacity or ancillary services over the Transmission System from the Point of Delivery of the Linden VFT Facility for at least the same time period as the Linden VFT Schedule provided under this Schedule 16-A. Reserving such Transmission Service from the Linden VFT Facility is a required precondition to acquiring a Linden VFT Schedule. The Linden VFT Transmission Customer is responsible for all charges associated with Transmission Service for delivery of capacity and energy from the Point of Delivery of the Linden VFT Facility.

5. Liability

The Transmission Provider and any holder of a Linden VFT Reservation which releases or resells its Linden VFT Reservation through resale procedures set forth in Section 3.5 and 3.7 of this Schedule 16-A shall be held harmless with regard to any claim which may be raised by any party regarding the award of the released Linden VFT Reservation, except to the extent that such party successfully establishes that the releasing party has incorrectly selected the party

acquiring such released Linden VFT Reservation as the result of gross negligence or willful misconduct. The liability of the Transmission Provider shall be limited by the terms and conditions of Section 10 of the Tariff and the provisions of the Operating Agreement.

6. Losses and Inadvertent Energy

Real power losses and inadvertent energy across the Linden VFT Facility shall be allocated solely to Linden VFT Transmission Customers that schedule Firm or Non-Firm transmission service over the Linden VFT Facility on an hourly pro rata basis, except for hours with no Linden VFT Schedules, in which case any real power losses and inadvertent energy across the Linden VFT Facility shall be allocated to Linden VFT Transmission Customers that schedule Firm or Non-Firm transmission service over the Linden VFT Facility on a monthly pro rata basis.

7. Congestion Costs and FTRs

A Linden VFT Schedule provides a physical right to deliver energy over the Linden VFT Facility. Accordingly, no congestion costs shall be calculated over the Linden VFT Facility and no FTRs or their equivalent shall be offered for a Linden VFT Schedule. This provision is not meant to preclude any allocation of financial transmission rights, auction revenue rights or their equivalent awarded to the Linden VFT Transmission Owner pursuant to Part VI of the Tariff. Such rights would be allocated to Primary Rights Holders in accordance with Section 2.1.

8. Measurement and Posting of ATC and TTC

The ATC and TTC of the Linden VFT Facility shall be calculated and posted on the OASIS by the Transmission Provider consistent with the requirements of the Tariff.

9. Payment of Other Charges Required for a Linden VFT Schedule

The Linden VFT Transmission Customer is responsible for charges applicable to a Linden VFT Schedule provided under this Schedule 16-A, including, but not limited to, any congestion and loss charges, redispatch costs, transitional revenue neutrality charges, scheduling, administrative, hardware or software upgrade charges, control area or administrative services charges or ancillary service charges applicable to the Transmission Provider's administration of transmission service over the Linden VFT Facility (collectively, the "Linden VFT Service Administration Charges"). In the event that any such Linden VFT Service Administration Charges are billed by the Transmission Provider to the Linden VFT Transmission Owner, the Linden VFT Transmission Owner may bill the Linden VFT Transmission Customer for such charge, and the Linden VFT Transmission Customer shall pay the Transmission Provider, on behalf of the Linden VFT Transmission Owner, such Linden VFT Service Administration Charges pursuant to this Section 9 as a condition of receiving transmission service over the Linden VFT Facility.

In the event that any other charges related to the construction, maintenance, operation or upgrading of the Transmission System are assessed by the Transmission Provider to the Linden

VFT Transmission Owner for the use of the Linden VFT Facility for injection of energy or capacity into the Transmission System, the Linden VFT Transmission Owner may bill the Primary Rights Holder, and the Primary Rights Holder shall pay the Transmission Provider, on behalf of the Linden VFT Transmission Owner, such charges pursuant to this Section 9 as a condition of receiving transmission service over the Linden VFT Facility. The issuance and time for payment of charges under this Schedule 16-A shall be consistent with the billing and payment provisions of Section 7 of the Tariff.

Any failure of a Linden VFT Transmission Customer or a Primary Rights Holder to pay any of the charges referenced in this Section 9 shall be deemed a failure to pay by the Linden VFT Transmission Owner.

EXHIBIT A TO SCHEDULE 16-A

Form of Service Agreement for
Transmission Service for Imports over the Linden VFT Facility

1.0 This Service Agreement, dated as of _____, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the "Transmission Provider") and _____ ("Linden VFT Transmission Customer").

2.0 The Linden VFT Transmission Customer has been determined by the Transmission Provider to have a Completed Application for a Linden VFT Reservation under the Tariff.

3.0 If required, the Linden VFT Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) 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.

5.0 The Transmission Provider agrees to provide and the Linden VFT Transmission Customer agrees to take and pay for the Linden VFT Reservation in accordance with the provisions of Schedule 16-A of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representatives as indicated below.

Transmission Provider PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, PA 19403-2497
Linden VFT Transmission Customer _____ _____ _____

7.0 The Tariff, including Schedule 16-A, 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:	_____	_____	_____
	Name	Title	Date

Linden VFT Transmission Customer:

By:	_____	_____	_____
	Name	Title	Date

CERTIFICATION

I, _____, certify that I am a duly authorized officer of _____ (Linden VFT Transmission Customer) and that _____ (Linden VFT 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.

_____
(Name)

_____
(Title)

Subscribed and sworn before me this _____ day of _____, _____.

_____
(Notary Public)

My Commission expires: _____

Specifications For Transmission Service for Imports Over Linden VFT Facility

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted.
_____

3.0 Point of Receipt: NYISO (at the Linden Cogen 345 kV ring bus in Linden, New Jersey)

Delivering Party: _____

4.0 Point of Delivery: VFT Switching Station in Linden, New Jersey

Receiving Party: _____

5.0 Maximum amount of energy to be transmitted (Reserved Transmission Capability):
_____

6.0 Designation of party(ies) subject to reciprocal service obligation:
_____
_____
_____

8.0 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 and Schedule16-A).

8.1 Linden VFT Reservation Charge:
_____
_____

8.2 Linden VFT Service Administration Charges:

_____
_____

8.3 Linden VFT Transmission Enhancement Charges:

_____

ATTACHMENT A-1

Form Of Service Agreement For
The Resale, Reassignment Or Transfer Of
Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between _____ (the Transmission Provider) as the administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and _____ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

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:

_____

_____

_____

Counterparty:

_____

_____

_____

Assignee:

_____

_____

_____

6.0 The Tariff 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.

Transmission Provider:

By:_____ _____ _____
Name Title Date

Counterparty:

By:_____ _____ _____
Name Title Date

Assignee:

By:_____ _____ _____
Name Title Date

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt:_____

Delivering Party:_____

4.0 Point(s) of Delivery:_____

Receiving Party:_____

5.0 Maximum amount of reassigned capacity: _____

6.0 Designation of party(ies) subject to reciprocal service obligation: _____
_____
_____
_____

7.0 Name(s) of any Intervening Systems providing transmission service: _____
_____

8.0 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.)

8.1 Transmission Charge: _____
_____

8.2 System Impact and/or Facilities Study Charge(s):
_____
_____

8.3 Direct Assignment Facilities Charge:_____
_____

8.4 Ancillary Services Charges: _____
_____
_____
_____
_____
_____
_____

9.0 Name of Reseller of the reassigned transmission capacity:
_____

ATTACHMENT C

Methodology To Assess Available Transfer Capability

The Transmission Provider will be solely responsible for determinations of Available Transfer Capability (ATC). The Transmission Provider will post firm and non-firm ATC projections on the OASIS for interfaces between neighboring Balancing Authorities and the PJM Region, and other path locations of significant commercial interest will be added as appropriate.

ATC of a particular path is an approximate indication of the anticipated transmission transfer capability remaining on the transmission network that could be scheduled for further commercial activity relative to the designated path under the conditions studied. Specific study of conditions, including source and sink of generation and load, is required before firm transmission service commitments can be made.

Transfer capability of the transmission network is limited by physical and electrical characteristics of the system including thermal equipment loading, voltage, and stability considerations and provisions of coordination agreements. Transfer capability is evaluated based on base system loading and an assessment of critical contingencies on the transmission system. The critical contingencies will be defined as appropriate. The Transmission Provider's calculation of transfer capability will be consistent with the principles in the NERC standards. These calculations will be performed through a combination of planning and operational analyses, employing both Energy Management System real-time functionality and off-line analytical tools as appropriate. Firm and non-firm ATC will be determined consistent with NERC standards, taking into account the Transmission Reliability Margin (TRM), Existing Transmission Commitments (ETC) and Capacity Benefit Margin (CBM) (see below) in order to preserve the emergency capability of the PJM Region to serve load serving entities. Firm ATC on any path will be limited to assure that emergency import capability will be available to Network Customers when needed through the reservation of capacity benefit margin, equivalent to a firm point-to-point transmission service reservation for delivery from systems outside of the PJM Region to serve the load serving entities within such region.

Determination of ATC requires that base system conditions be identified and modeled for the period being analyzed. These conditions include projected demand, anticipated generation availability, anticipated transmission system facility availability, expected energy transactions, and information about neighboring regions that affect the transfer capability of the PJM Region. For hourly through monthly calculations, these conditions are based on the Transmission Provider's operational assessments of load trends, unit commitment profiles, maintenance schedules and ETC. Long-term calculations are based on planning loads, expected maintenance schedules, typical generation patterns, and ETC.

Any dispute regarding a determination of ATC by the Transmission Provider, or regarding the data used by the Transmission Provider in such a determination, shall be resolved pursuant to the dispute resolution procedures of Section 12 of this tariff.

ATC and AFC Calculations Using Flowgate Methodology

The Available Flowgate Capability (AFC) calculation methodology used by the Transmission Provider is the Flowgate Methodology as described in the Available Transfer Capability Implementation Document (ATCID). The ATCID is included on the PJM OASIS page under ATC information . The Flowgate Methodology uses analytical tools to examine critical flowgates over the PJM Region and adjacent regions (per seams agreements) and converts AFC values into particular path ATC values, which are posted on the PJM OASIS. For Firm and Non-firm Transmission Service ATC calculations the Transmission Provider shall account for Postbacks of redirected services, unscheduled service, and counterflows. PJM critical flowgates may include, but are not limited to thermal flowgates, voltage/stability flowgates, coordinated flowgates, and reciprocal coordinated flowgates.

Overview and Process Flow Diagram

The process for the Transmission Provider's AFC/ATC calculation is illustrated in the Exhibit 1 flow diagram. The text that follows describes the inputs, outputs and processes performed within each of the sub-processes contained in Exhibit 1. The Transmission Provider calculates Firm and Non-firm Transmission Service ATC for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule), and planning horizon (beyond the operating horizon).

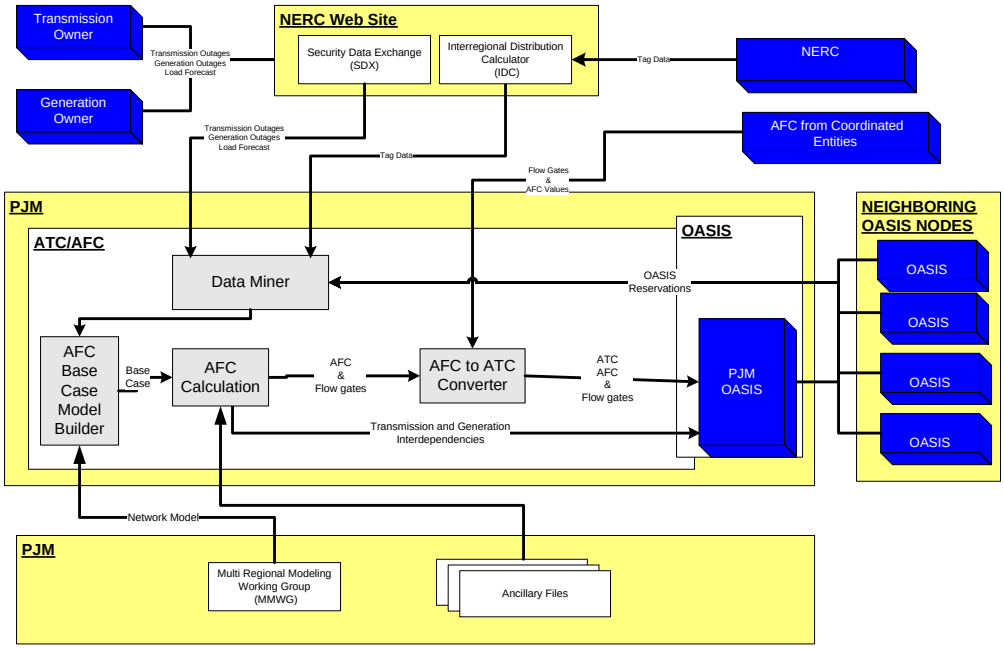


Exhibit 1

AFC Flowgate Methodology

Determining AFC and ATC using the Flowgate Methodology is a multi-step integrated process which is described in detail in the ATCID. PJM uses the following mathematical algorithms to calculate AFC and ATC. The actual detailed AFC and ATC algorithms are available on the PJM OASIS website at the following link:

ftp://ftp.pjm.com/oasis/afc-atc-algorithms.pdf

AFC = flowgate rating – ETC – TRM – CBM + Postbacks + counterflows.

The AFC Calculation is the amount of unused transfer capability on a flowgate after accounting for base case conditions represented by solved base case flows and applying the impacts of non-base case commitments and flowgate specific margins.

$$ATC = \text{Minimum}\{AFC_1 / \text{Transfer Response Factor}, \ldots, AFC_n / \text{Transfer Response Factor}\}$$

The AFC to ATC converter translates the flowgate AFC values into path ATC values for posting to the OASIS. The ATC calculation is the minimum AFC of a set of limiting flowgates divided by the transfer response factor or distribution factor on the respective flowgate for a specific Point of Receipt/Point of Delivery pair. The Available Share of Total Flowgate Capability (ASTFC) as prescribed by a congestion management process agreement (e.g., the CMP included in the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM) may be less than the calculated AFC. The posted AFC is set by the ASTFC or the calculated AFC, whichever is most limiting.

An overview of the major components of this process is described below:

- The AFC to ATC converter process utilizes the coordination entity calculated AFC values for non-PJM flowgates. AFC values for coordination entity flowgates calculated by the coordination entity overwrite values that the Transmission Provider's process determines for these Flowgates.

- The Transmission Provider supplies coordination entities with similar values for PJM Flowgates for inclusion in the coordination entity's AFC process.

- Values provided to the OASIS from the AFC/ATC process are continually updated on the OASIS to reflect the reservations or schedules that were accepted or confirmed since the last complete calculation cycle.

Data Miner

Transmission Provider, through data miner process, gathers data from the Transmission Provider and external sources to use as inputs to the AFC/ATC process. These external sources are included in the Transmission Provider's ATCID.

Model Builder

The Transmission Provider develops and maintains seasonal models for the next 18 months. These seasonal models will be developed from the NERC MMWG case library modified for any known model updates. The Transmission Provider's AFC/ATC calculations are based on these seasonal models. The model builder portion of the AFC/ATC engine modifies these seasonal base cases to reflect anticipated conditions such as forecasted load levels, outages, generation dispatch files, and base case transfers (reservations and/or schedules as appropriate) for the AFC/ATC time horizon. The base case models are refined to reflect transmission outages and generation unavailability as provided by the NERC SDX data. Load levels are appropriately adjusted to reflect the modeled conditions using the NERC SDX data. Relevant balancing authorities external to the PJM footprint will be modeled at the appropriate load level with the generation scaled to match loads.

The Transmission Provider develops monthly, weekly, daily, and hourly AFC cases. These cases serve as the base case models for the AFC calculation for a specific period. Solved base

case models for monthly, weekly, daily, and hourly time frames are developed multiple times each day consistent with NERC standards.

The Transmission Provider models some flowgates without contingencies and some with contingencies.

The flowgates modeled without contingencies are the Power Transfer Distribution Factor (PTDF) flowgates, which are flowgates where a single facility or multiple transmission facilities are monitored for a limiting condition. The limiting condition can be due to thermal loading above 100% of the normal rating or due to a thermal rating above 100% of the surrogate rating representing an equivalent voltage or stability limit.

The flowgates modeled with contingencies are the Outage Transfer Distribution Factor (OTDF) flowgates, which are flowgates where a single facility or multiple transmission facilities are monitored for a limiting condition after a contingency event has been simulated to have occurred (one or multiple facilities for the loss of another facility or facilities). The limiting condition monitored can be due to thermal loading above 100% of the 4 hour emergency rating.

For flowgates owned by other parties, Transmission Provider uses the limit provided by that party, subject to the terms of the AFC Coordination and Congestion Management Process sections of the applicable agreements between Transmission Provider and the other parties.

AFC Calculation

The Transmission Provider's AFC/ATC calculation implements the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the Transmission Provider shall account only for firm commitments; (2) for non-firm ATC calculations, the Transmission Provider shall account for both firm and non-firm commitments. Reservations from the PJM and non-PJM OASIS sites are utilized. Flow based analysis will be used to determine and update flowgate loadings for reservations not modeled in the base case and to determine response factors on each flowgate. Flowgate loadings and response factors will be used to determine the individual path ATC values.

- The Transmission Provider recognizes physical network limitations (i.e., flowgates) on PJM and appropriate non-PJM systems in the determination of the path ATC values.

- AFC values received from coordination entites are calculated by those entities according to their AFC methodology.

AFC to ATC Conversion

To calculate ATC, which represents a transfer capability in MW available for sale between a specific Point of Delivery and Point of Receipt, the Transmission Provider will first calculate an AFC for each flowgate. An AFC is defined as follows:

- The available capability in MW on a flowgate, determined by the transmission provider, that is available for further commercial activity. The available capability determined will be dependent on the generation, loads and transmission configuration assumed for the time period studied.

- The AFC accounts for thermal, voltage and stability limits under both pre and post contingency conditions, along with any existing transmission commitments, TRM and CBM.

- The AFC is used to determine the amount of MWs that can be transferred between a specific set of source and sink points. An AFC is skipped using on-the-path logic if the flowgate owner is either the Point of Receipt or Point of Delivery on the path being calculated. The non-firm ATC calculation for the willing-to-pay congestion product on the OASIS includes only external flowgates.

- Counterflow and Postbacks are considered in the calculation of AFC.

Coordination with Neighboring Systems

The Transmission Provider exchanges data with neighboring systems. The Transmission Provider provides transmission reservations, AFC values for Transmission Provider flowgates, and other data. This coordination results in comparable inputs to the AFC calculations. The Transmission Provider utilizes similar information provided by coordinating entities.

Treatment of Existing Transmission Commitments

ETC is committed use of the transmission system, including: (1) Transmission Provider's reservations in accepted or confirmed status; (2) native load commitments; Network Integration Transmission Service; (3) grandfathered transmission rights; (4) Firm Point-To-Point Transmission Service reservations; and if required (5) rollover rights associated with long-term firm service (Point-To-Point Transmission Service and Network Integration Service or grandfathered transmission rights). Existing commitments modeled in the load flow base cases determine the initial flows on the facilities. To the extent there are existing transactions that qualify for rollover rights, they are incorporated in the committed usage.

PJM OASIS reservations that are withdrawn, retracted (not confirmed) or annulled are removed from the ETC and any resulting changes to ATC are incorporated in the next OASIS posting of ATC calculated values. The Transmission Provider's firm and non-firm ATC calculations also account for permanently redirected services, unscheduled service, and counterflows. In the scheduling and operating horizons, reservation impacts are substituted with scheduled impacts. That is, the reservation impact component of ETC is set to zero and the schedule impacts component of ATC is used. In the planning horizon, reservation impacts are used because requests to schedule are often not received in this horizon. That is, the reservation impact component of ETC is set based on Transmission Service Requests for which Transmission Provider has committed to provide service and the schedule impacts component of ATC is set to zero. Additional information is included on this subject in the Transmission Provider's ATCID.

External Flowgates

Flowgates are used in the AFC and ATC calculations. PJM adds or eliminates external flowgates based on the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C. ("Midwest ISO JOA", Article V (FERC Electric Tariff, First Revised Rate Schedule No. 38, *see*, Section 4.2 – Cost of Data and Information Exchange up to and including Section 5.1.12 – Coordination of Transmission Reliability Margin Values); Joint Operating Agreement Among And Between PJM Interconnection, L.L.C., And Progress Energy Carolinas ("PEC JOA"), Article Five (FERC Electric Tariff, First Revised Rate Schedule No. 50, *see*, Article 9 – Coordinated Transmission Planning Studies up to and including Article 12 – Managing Pareallels Flow on the VACAR/PJM Interface); and Joint Reliability Coordination Agreement Among And Between Midwest Independent Transmission System Operator, Inc., PJM Interconnection, L.L.C., And Tennessee Valley Authority ("JRCA"), Article Five (the JRCA is not a filed FERC rate schedule; however, Article Five of the JRCA is identical to Article V of the Midwest ISO JOA and Article Five of the PEC JOA). PJM adds or eliminates internal flowgates, at least annually, based on a review of historic operating constraints including flowgates that have been in Transmission Loading Relief (TLR) and other operating conditions as deemed appropriate.

Internal Flowgates

Transmission Provider determines base case flows using the AFC engine. Transmission Provider runs the AFC engine hourly (except in the case of a technical error, system error or planned system outage). The base run includes native and network load (from the load forecast), transmission service that is expected to be scheduled (grandfathered, point-to-point and imports from designated Network Resources), outages and load forecast. Base case flow inputs are updated at least once per day. In the scheduling and operating horizons, Transmission Provider updates scheduled transmission service for each run of the AFC engine. Transmission Provider models all grandfathered agreements and other non-Tariff use of the transmission system as firm service or load. Transmission Provider does not segregate non-Tariff service in the AFC calculation.

On an annual basis (or sooner if required by NERC MOD Standards), PJM shall review internal flowgates using the following methodology:

a. The Transmission Provider shall include all flowgates in its footprint that have initiated a TLR event in the 12 months prior to the annual review.

b. The Transmission Provider shall include applicable System Operating Limit (SOL) and Interconnection Reliability Operating Limits (IROL) flowgates per NERC TOP-002 R-12 standards (or successor). Any facility that PJM monitors that is not considered an IROL facility is consider a SOL. Applicable SOL and IROL flowgates shall include at a minimum those flowgates identified in the TRM process described in this Attachment C AFC process.

c. The Transmission Provider shall add or remove flowgates to its AFC process in accordance with NERC MOD standards.

The Transmission Provider may eliminate flowgates that do not continue to meet the criteria above.

A reservation with rollover rights is reflected in ETC in the amount of transmission service reserved as if the customer has exercised its rollover right. If the deadline for a customer to exercise its rollover right for a given reservation has passed, and the customer did not exercise its rollover right, the amount associated with the unexercised rollover right no longer is included in the amount of reservations.

Treatment of Capacity Benefit Margin

Explanation of CBM

Transmission Provider uses the NERC approved definition of CBM, which is the amount of firm transmission transfer capability preserved by Transmission Provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by an LSE only in times of emergency generation deficiencies. Additional information is included in the Transmission Provider's Capacity Benefit Margin Implementation Document (CBMID) posted on the PJM OASIS page under ATC Information.

The CBM is a reliability margin applied to the flowgate in the AFC Calculation. CBM is only applied to firm ATC calculations where the PJM Region is the delivery point. The Transmission Provider consistently applies CBM in planning and operations and does not double count for this reliability margin (i.e., this margin is not included in TRM). For non-PJM flowgates, the Transmission Provider uses the CBM values provided by coordination entities for the AFC calculation on these flowgates.

Through the sharing of installed generating capacity via transmission interconnections, systems have relied on transmission import capability to reduce their required installed generating capacity necessary to provide reliable service to Network Customers. In order to ensure that PJM has the ability to import external generation for the purpose of serving Network Customers, a portion of the transfer capability will be set aside. CBM is set aside on paths based on the expected delivery of energy from entities with which the Transmission Provider has emergency energy agreements at the time of the Transmission Provider's forecast peak load. This capability, known as the Capacity Benefit Margin, is a reflection of the mutual benefit of interconnected operations and reservation of this margin allows a system to reduce its installed generating capacity below that which may have otherwise been required if transmission interconnections did not exist.

The CBM is determined through the auspicious of the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (PJM Rate Schedule FERC No. 44) (RAA). Capitalized terms in this section that are not defined in this section or section 1 of the Tariff are defined in the RAA.

CBM is determined through the Transmission Planning Evaluation of Import Capability. This evaluation establishes the amount of emergency power that can be reliably transferred to the PJM Region from adjacent regions in the event of a PJM Region generation capacity deficiency. To determine the import transfer limit, several emergency scenarios are replicated and the limit represents a normalization of expected values. This transfer limit determines the PJM Region tie benefit that is subsequently used in calculating the PJM Region reserve requirement. An annual recalculation of the PJM Region import capability is not required, since the import capability far exceeds the CBM value specified in Schedule 4 of the RAA.

CBM is a key input into the annual resource adequacy study performed by Transmission Provider. The purpose of this study is to determine the PJM Region Installed Reserve Margin (IRM) required by the PJM Region to satisfy a one day in 10 year Loss of Load Expectation (LOLE). Transmission Provider uses a probabilistic methodology to perform the resource adequacy study. The study assumptions and results are subject to stakeholder review and comment. The resulting IRM is expressed as a percentage of the forecasted annual peak load.

The CBM assessment in the PJM Region is a unique method that is regionally specific because interface capability greatly exceeds CBM and because Transmission Provider centrally secures capacity for the PJM Region capacity market.

Transmission Provider's annual resource adequacy study is based on the probabilistic methods and criteria described in Schedule 11 of the RAA, the Operating Agreement and in the PJM Manuals. The resource adequacy study considers the following data and forecasts as necessary:

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

2. Forecasts of aggregate seasonal load shape of the parties bound by the RAA which are consistent with forecast averages of 52 weekly peak loads prepared by Transmission Provider.

3. Variability of loads within each week, due to weather, economic forecast uncertainty, and other recurring and random factors, as determined by Transmission Provider.

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

5. Generator Forced Outage rates for existing mature generating units based on data submitted by generation owners, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

6. Generator Maintenance Outage factors and planned outage requirements based on forecasts and historical data submitted by the generation owners.

7. Miscellaneous adjustments to capacity due to all causes, as determined by the Office of the Interconnection, based on forecasts submitted by the generation owners.

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

The value of the capacity benefit margin as filed as part of the RAA periodically is reviewed by Transmission Provider, in consultation with the Members Committee, and can be modified, if necessary, to balance external emergency capacity assistance and internal installed capacity reserves so as to minimize the total cost of the capacity reserves of the RAA participants, consistent with the Reliability Principles and Standards.

Use of CBM in an Emergency

The procedures for the use of CBM in an emergency, are described in Section 2 of PJM Manual 13: Emergency Operations and are consistent with NERC and ReliabilityFirst Corporation's Energy Emergency Alert defined in NERC's EOP-002 standards. Transmission Provider is responsible for declaring the existence of an emergency, and for directing the operations of the PJM Members as necessary to manage, alleviate, or end a capacity shortage. Transmission Provider uses CBM in an emergency only on behalf of LSEs. LSEs only use CBM through the Transmission Provider's use of CBM on the LSEs behalf.

Emergency use of CBM will be considered use of Network Integration Transmission Service and there will be no additional charge for such use. Because an area is in an EEA 2 and Transmission Provider is taking steps to avoid shedding firm load, the use of CBM will have a NERC curtailment priority of 7 and will only be curtailed with other firm uses on a proportional basis.

Transmission Provider utilizes CBM on behalf of LSEs as described below.

- Transmission Provider reviews the level of dependency on external transactions to serve the load in the PJM Region. Transmission Provider shall log occurrences where CBM is implemented. Transmission Provider shall notify external systems via the Reliability Coordinator Information System (defined in NERC EOP-002) or successor, a communications tool located at the NERC website to post potential or actual alert information, and Transmission Provider Members via the Transmission Provider's website and issue appropriate NERC alert levels consistent with NERC EOP- 002.

- CBM shall be used only after the following steps have been taken: all non-firm sales have been terminated, direct-control load management has been implemented, and customer interruptible demands have been interrupted. Due to the nature of emergencies, Transmission Provider may skip or reorder the steps in accordance with Good Utility Practice. CBM may be used to reestablish Operating Reserves.

- CBM shall only be used if the PJM Region is experiencing a generation deficiency to increase generation in the PJM Region. Transmission Provider shall use CBM, on behalf

of an LSE, in order to exercise emergency energy agreements and to implement approved emergency energy bids. Transmission Provider does not displace Non-Firm Point-To-Point Transmission Service and/or secondary service, described in section 28.4 of the Tariff, imports until the Transmission System is constrained. If the Transmission System is constrained, CBM is used by Transmission Provider to displace such imports to provide more reliable service to load during capacity deficiencies.

- Unused CBM is included in the AFC/ATC calculations as Non-Firm Point-To-Point Transmission Service and/or secondary service, described in section 28.4.

Transmission Planning Evaluation of Import Capability

The Transmission Provider conducted an Expected Import Capability Study (EICS) to evaluate the emergency import limits of the Transmission Provider under summer peak conditions. That study showed the Transmission Provider's import capability limit. This limit is evaluated annually to assess whether the CBM value should be changed. This evaluation is discussed in the annual PJM Reserve Requirement Study (RRS). While the Transmission Provider can import more than the CBM value issued in the study, the additional import capability is reflected in ATC through the OASIS postings. This allows the additional import capability to be used in the marketplace. The reliability benefit of CBM saturates near the limit issued in the RRS.

Treatment of Transmission Reliability Margin (TRM)

The Transmission Reliability Margin (TRM) is a reliability margin applied to the flowgate in the AFC Calculation. TRM accounts for the inherent uncertainty in system conditions and its associated effects on ATC calculations and the need for operating flexibility to ensure reliable system operation as system conditions change. The Transmission Provider, following the NERC MOD-008-1, or successor Reliability Standard, calculates TRM for flowgates and may include uncertainty items using a process described in the Transmission Reliability Margin Implementation Document (TRMID). The flowgates are identified following NERC MOD-030-2, or successor Reliability Standard, through processes described in the ATCID. Both the TRMID and ATCID are posted PJM OASIS page under ATC Information.

Transmission Provider calculates TRM using the following methodology:

1. TRM shall be set using components of uncertainty i~~n~~dentified in the TRMID for all PJM flowgates except as noted below.

2. TLR and IROL. TRM shall be considered using components of uncertainty identified in the TRMID for all flowgates that had TLR issued in the 12 months prior to Transmission Provider's annual TRM re-evaluation and are Interconnection Reliability Operating Limits (IROLs) located in PJM Manual 37: Reliability Coordination.

3. Constrained Operations. TRM may be set using components of uncertainty identified in the TRMID for flowgates that were bound constrained in the 12 months prior to Transmission Provider's annual TRM re-evaluation.

4. Current and Expected Operating Conditions. During times of unusual circulation or other operating conditions, Transmission Provider may set a larger TRM than indicated in sections 1, 2, and 3.

5. Historic Conditions. Notwithstanding sections 1, 2, and 3 above, Transmission Provider may set TRM on specific flowgates consistent with components of uncertainty identified in the TRMID and NERC MOD-008-1, or successor Reliability Standard.

6. For non-PJM flowgates, the Transmission Provider uses the TRM values provided by coordination entities for the PJM AFC calculation on these flowgates in accordance with applicable agreement with such entities.

Transmission Provider uses data from Transmission Provider's Energy Management System (EMS) historic database, IROL and NERC's Interchange Distribution Calculator (IDC) in the calculation of TRM.

Transmission Provider uses TRM in all AFC calculations. Transmission Provider includes TRM in the AFC/ATC calculation to provide a reasonable level of assurance that the interconnected transmission network will be secure. TRM is not scheduled against or explicitly used for the delivery of energy. It is preserved as a reliability margin to reflect the uncertainty of the operation of the electric system (i.e., to prevent oversubscription of the transmission system). Transmission Provider flowgates with their TRM, CBM, and ratings are posted on the PJM OASIS paged under ATC Informatiion at:

ftp://ftp.pjm.com/oasis/fgates-definitions-posting.csv

Total Transfer Capability (TTC)

The Total Transfer Capability (TTC) is the amount of transfers that can be reliably delivered across the interconnected transmission system for the forecasted conditions. The Transmission Provider uses the network AFC methodology to calculate ATC, which does not use TTC as an input. The flowgate rating is an equivalent starting point in the AFC calculation. However, a TTC value is derived as an output and is posted.

ATTACHMENT F-1

Form of Umbrella Service Agreement for Network Integration Transmission Service Under State Required Retail Access Programs

1.0 This Service Agreement dated as of _____, including the Specifications For Network Integration Transmission Service Under State Required Retail Access Programs attached hereto and incorporated herein, is entered into, by and between PJM Interconnection, L.L.C. ("Transmission Provider") as administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and _____, a transmission customer participating in a state required retail access program and/or a program providing for the contractual provision of default service or provider of last resort service ("Network Customer").

2.0 The Network Customer has been determined by the Transmission Provider to have a valid request for Network Integration Transmission Service under the Tariff and to have satisfied the conditions for service imposed by the Tariff to the extent necessary to obtain service with respect to its participation in a state required retail access program.

3.0 Service under this Service Agreement shall commence on _____, and shall terminate on such date as mutually agreed upon by the parties, unless state law or regulations specify a limited period for service or unless earlier terminated for default under Section 7.3 of the Tariff.

4.0 The Transmission Provider agrees to provide, and the Network Customer agrees to take, Network Integration Transmission Service in accordance with the Tariff, including the Operating Agreement of the PJM Interconnection, L.L.C. ("Operating Agreement") (which is the Network Operating Agreement under the Tariff and 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

Network Customer

_____

_____

_____

IN WITNESS WHEREOF, the Transmission Provider and the Network Customer have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider

By:_____ _____ _____
Name Title Date

Counterparty:

By:_____ _____ _____
Name Title Date

Network Customer

By:_____ _____ _____
Name Title Date

SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE
PURSUANT TO STATE REQUIRED RETAIL ACCESS PROGRAMS

1.0 Term of Service: The term of service under this Service Agreement shall be from _____ until terminated by mutual agreement of the parties, unless state law or regulations specify a limited period for service or unless earlier terminated for default under Section 7.3 of the Tariff.

2.0 Network Operating Agreement: In accordance with Section 29.1 of the Tariff, the Network Customer must be a member of PJM Interconnection, L.L.C. and a signatory to the Operating Agreement.

3.0 Network Load and Network Resources: The Network Customer shall be responsible for the Transmission Provider receiving the information pertaining to Network Load, Network Resources, and Behind The Meter Generation described in this section. Such information shall be provided in accordance with procedures established by the Transmission Provider. With respect to service requests under this umbrella Service Agreement, the Transmission Provider will deem the provision of the information specified in this section as complying with the application requirements set forth in Section 29.2 of the Tariff.

3.1 Network Load: For Network Load within the PJM Region, the Network Customer shall arrange for each electric distribution company ("EDC") delivering to the Network Customer's load to provide directly to the Transmission Provider, on a daily basis, the Network Customer's peak load (net of operating Behind The Meter Generation, but not to be less than zero, unless such generation is separately metered and reported to PJM), by bus, coincident with the annual peak load of the Zone as determined under Section 34.1 of the Tariff. The peak load shall be expressed in terms of tenths of a megawatt and shall include all losses within the PJM Region, including other transmission losses, and distribution losses. Unless a more specific bus distribution is available, the EDC may provide a bus distribution for the Network Customer's peak load proportional to the bus distribution for all of the load in the Zone. The information must be submitted directly to the Transmission Provider by the EDC, unless the Transmission Provider approves in advance another arrangement. For Non-Zone Network Load, the Network Customer shall provide to the Transmission Provider, on a daily basis, the Network Customer's peak load, by interconnection at the border of the PJM Region, coincident with the annual peak load of such area as determined under Section 34.1 of the Tariff. The peak load for such Non-Zone Network Load shall be expressed in terms of tenths of a megawatt and shall not include losses within the PJM Region. Unless a more specific bus distribution is identified and node definition requested, a service request shall be granted upon submission of the information set forth in this Section 3.1 without any further confirmation procedures. If a Network Customer under this Service Agreement, prior to the commencement of service or at any time after the commencement of

service, identifies a more specific bus distribution and requests a node definition for all or part of its Network Load that is served under state required retail access programs, the Network Customer shall notify both the Transmission Provider and the electric distribution company pursuant to the notification procedure and schedule set forth in the PJM manuals. The Transmission Provider, exercising its independent judgment and expertise, shall have the authority to resolve any difference of opinion that may arise between the Network Customer and the electic distribution company as to the applicable bus distribution or node definition. If confirmed, the more specific bus distribution will not be used for billing and settlement purposes, however, until the notification procedure set forth in the PJM manuals is completed, and in no event until June 1, to correspond with the commencement of the annual planning period.

3.2 Network Resources: The Network Customer, as necessary, shall designate from time to time its Network Resources. In the event the Network Resource to be designated is Behind The Meter Generation, the designation must be made before the commencement of a Planning Period as that term is defined in the Operating Agreement and will remain in effect for the entire Planning Period. Such Network Resources must be acceptable to the Transmission Provider as Network Resources in accordance with the Tariff and the Operating Agreement. Designations of resources that have not previously been accepted as Network Resources of any Network Customer or Transmission Customer shall include the information set forth in Section 29.2(v) of the Tariff. Changes in the designation of Network Resources will be treated as an application for modification of service. The Network Customer shall confirm the acceptance of a Network Resource within 15 days of the completion of a System Impact Study or 30 days after completion of a Facilities Study, as is applicable. The Transmission Provider will maintain a current list of Network Resources, which shall be updated from time to time.

3.3 Hourly Load: The Network Customer and/or the EDCs delivering to the Network Customer's load shall provide to the Transmission Provider, on a daily basis, hourly loads and an associated bus distribution for the Network Load. For Network Load within the PJM Region, hourly loads required under this Section shall include all losses within such area, including transmission losses, and distribution losses. The Network Customer shall notify the Transmission Provider whether the Network Customer or the EDC will submit the hourly loads. The submitted load values will include losses and shall be reduced using the applicable loss factor determined by the Transmission Provider whenever a billing determination is calculated under the Tariff without losses.

3.4 Energy Schedules: The Network Customer shall schedule energy for its hourly loads in accordance with the Appendix to Attachment K of the Tariff.

3.5 Interruptible Loads: The Network Customer shall inform or shall arrange for each EDC delivering to Network Customer's load to inform Transmission Provider about the amount and location of any interruptible loads included in the Network

Load. This information shall include the summer and winter peak load for each interruptible load (had such load not been interruptible), that portion of each interruptible load subject to interruption, the conditions under which an interruption can be implemented, and any limitations on the duration and frequency of interruptions.

3.6 Procedures for Load Determination: The procedures by which an EDC will determine the peak and hourly loads reported to the Transmission Provider under Sections 3.1 and 3.3 may be set forth in a separate schedule to the Tariff for each EDC.

3.7 Behind The Meter Generation: For Behind The Meter Generation of a Network Customer that requires metering pursuant to section 14.5 of the Operating Agreement, the Network Customer shall arrange for the Transmission Owner or EDC to provide directly to Transmission Provider information pertaining to such Behind The Meter Generation and the total load at its location as necessary for PJM's planning purposes.

4.0 Energy Imbalance Service: The Network Customer will receive Energy Imbalance Service from the Transmission Provider in accordance with Schedule 4 of the Tariff. Energy Imbalance Service is considered to be PJM Interchange and will be charged at the hourly locational marginal price determined pursuant to Section 2 of the Appendix to Attachment K of the Tariff.

5.0 Reconciliation Billing: For Network Load within the PJM Region, to the extent required, the Transmission Provider will reconcile the Network Customer's hourly energy responsibilities as initially reported to Transmission Provider and its hourly energy consumption based on, or estimated from, metered usage, and provide corresponding charges and credits to Network Customer. Such reconciliation, if required, shall be made at the same rates as Energy Imbalance Service.

6.0 Designation of party subject to reciprocal service obligation: The Network Customer shall comply with Section 6 of the Tariff.

7.0 Name(s) of any Intervening Systems providing transmission service: To the extent any Network Resources are located outside the PJM Region, the list of Network Resources maintained by the Transmission Provider referenced in Section 3.2 of these specifications, shall identify any intervening systems needed to deliver those Network Resources to the Network Customer's retail load.

8.0 Charges: Service under this Service 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.)

8.1 Embedded Cost Transmission Charge: The embedded cost transmission charge shall be determined in accordance with the formula set forth in Section 34 of the Tariff.

8.2 System Impact and Facilities Study Charges: To the extent Network Resources are located outside, or a new resource is added to, the PJM Region, a System Impact Study and/or Facilities Study Agreement and related charges may be required pursuant to Section 32 of the Tariff.

8.3 Direct Assignment Facilities Charge: To the extent that facilities or portions of facilities must be constructed by a Transmission Owner for the sole use or benefit of the Network Customer to accommodate the service requested by the Network Customer, the Network Customer shall be responsible for the cost of such Direct Assignment Facilities, and the charges for such facilities shall be specified at the time that the Transmission Provider determines the facilities that are needed to provide the requested service.

8.4 Ancillary Services Charge: In addition to Energy Imbalance Service, Transmission Provider shall bill the Network Customer for ancillary services in accordance with Schedules 1, 1-A, 2, 3, 5, 6, and 9 of the Tariff. To the extent required, the ancillary services charges shall also be reconciled based on any differences between the Network Customer's hourly energy responsibilities as initially reported to Transmission Provider and its hourly energy consumption based on, or estimated from, metered usage.

8.5 Other Supporting Facilities Charge: None.

8.6 **[Reserved]**

8.7 Other Charges: Transmission Provider shall charge Network Customer any and all other charges set forth in the Tariff applicable to providing Network Integration Service.

9.0 Designated Agent: To the extent that a Designated Agent for one or more Network Customers provides to the Transmission Provider any of the information required by these Specifications, it shall provide the information separately for each Network Customer.

CERTIFICATION

I, _____, certify that I am a duly authorized officer of

_____ (Network Customer) and that

_____ (Network 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.

_____
(Name)

_____
(Name)

Subscribed and sworn before me this ____ day of _____, _____.

_____
(Notary Public)

My Commission expires:_____

2. Determination of Credit.

(a) **Overview.** For each hour with respect to which the Transmission Provider receives payments of Transmission Congestion Charges, determined in accordance with section A of this Attachment, Transmission Congestion Credits shall be allocated to the holders of Financial Transmission Rights. As explained in subsection B(1) above, the Financial Transmission Rights are associated with the points on the Transmission System between which the Firm Transmission User to whom the FTR was originally issued has arranged for the firm transmission of electric energy, whether on a network or point-to-point basis. Holders of FTRs receive credits attributable to the difference, if any, between Congestion Prices at the Point or Points of Receipt and the Point or Points of Delivery associated with the Financial Transmission Rights. As explained in Section 5.2.2 of Attachment K - Appendix, each FTR holder shares in Transmission Congestion Credits to the extent it holds Financial Transmission Rights between the Point or Points of Receipt and the Point or Points of Delivery at which congestion is experienced in a particular hour. Distribution of credits in this manner ensures that each FTR holder will not incur energy costs that are greater than the costs of energy from the generation resources associated with the FTR holder's Financial Transmission Rights. Target allocations of Transmission Congestion Credits to holders of Financial Transmission Rights are calculated in accordance with Section 5.2.5 of Attachment K – Appendix and Transmission Congestion Credits are distributed in accordance with that allocation, as described in Sections 5.2.5 and 5.2.6 of Attachment K – Appendix.

(b) **Assignment of Financial Transmission Rights.** Financial Transmission Rights shall be obtained pursuant to Attachment K - Appendix.

(c) **Assignment of Auction Revenue Rights.** Auction Revenue Rights shall be assigned pursuant to Attachment K - Appendix.

(d) **Target Allocation of Credits to Financial Transmission Rights.** Target Allocation of Transmission Congestion Credits for each FTR holder for each hour shall be pursuant to Attachment K – Appendix.

(e) **Distribution of Transmission Congestion Credits.** Distribution of Transmission Congestion Credits shall be pursuant to Attachment K – Appendix.

C. Offset of Transmission Congestion Charges and Transmission Congestion Credits.

The Office of the Interconnection, on behalf of PJMSettlement, shall take into account both (i) amounts payable by a Transmission User with respect to Transmission Congestion Charges as determined in accordance with Section A of this Attachment, and (ii) amounts payable to a Transmission User with respect to Transmission Congestion Credits as determined in accordance with Section B of this Attachment.

1.6A PJMSettlement

1.6A.1 Scope of Services

PJMSettlement shall perform the services pertaining to the PJM Interchange Energy Market specified in this Agreement, including, but not limited to, the following:

(i) PJMSettlement shall be the Counterparty to transactions (including ancillary services transactions) in the PJM Interchange Energy Market administered by the Office of the Interconnection;

(ii) PJMSettlement shall render bills to the Market Participants, receiving payments from and disbursing payments to the Market Participants; and

(iii) For purposes of clarity, PJMSettlement shall not be a Counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

ATTACHMENT M-2 (PSE&G)
PROCEDURES FOR LOAD DETERMINATION

The procedures by which PSE&G will determine the peak and hourly loads reported to the Transmission Provider are set forth in the following provisions.

A. CUSTOMER CAPACITY AND TRANSMISSION OBLIGATIONS

Both the capacity (generation) and transmission obligations for retail and wholesale customers have been developed so that the sum of the individual customer obligations within a zone will total the PJM zonal (LDC's) obligation. This zonal obligation may vary as provided for under the PJM Reliability Agreement due to the effects of net new customer load. PJM uses a "top down" method in allocating the PJM system peak load to each LDC, while the transmission loads are LDC (zone) specific. Each LDC uses a "bottom up" approach to calculate individual peak loads based upon the zonal loads. These preliminary customer peak loads are then scaled up or down to match (1) the normalized peak load calculated by PJM for each LDC for capacity purposes and (2) the actual zonal load for transmission purposes. Capacity peak loads, aggregated by Supplier, are adjusted for reserves and diversity by PJM. Transmission peak loads, aggregated by Supplier, transmitted to PJM need no further adjustment.

Since retail customers within a PJM zone (LDC service area) will be free to change suppliers, an obligation "tag" is needed to be assigned to each customer for both capacity and transmission obligations. These tags will be recalculated periodically to incorporate new customers, changing customer usage and to ensure consistency with the PJM and LDC peak loads and obligation calculations.

Discussed below is an explanation of how each individual customer's capacity and transmission peak load will be determined.

1. Customer Capacity Peak Load Determination

To calculate a retail and wholesale customer's capacity peak load share, the total normalized peak demand is first determined for each zone by PJM. In the case of the PSE&G zone, the normalized peak load in the Summer of 1998 was approximately 9200 MW. This normalized peak load was based upon allocating PJM's normalized peak load to PSE&G using the ratio between PSE&G's actual load and PJM's actual load during the five highest PJM peak hours.

In determining the peak load contribution for each of its customers, PSE&G will use the actual hourly meter readings for hourly (interval) metered customers at the time of the five highest peak hours for PJM. For non-hourly metered customers, summer kWh usage and billing demand information for each customer, along with load research (profile) data for customers in the same rate class will be used. There are several steps involved in the peak load calculation.

The first step requires the calculation of a preliminary peak load estimate for each customer based on the available information. For customers without demand meters, such as Rate Schedule RS, this preliminary peak will be based on the individual customer summer energy use

and the summer seasonal load factor (weather adjusted) calculated from the appropriate profile data. For customers with non time-of-day demand meters, such as Rate Schedule GLP, a similar calculation will be performed using appropriate weather adjusted profiled summer load factors, with the exception that the resulting customer peak load estimate will then be compared with the customer's maximum summer measured demand. The lower of the two values will be used for the preliminary peak load estimate. For customers with time-of-day demand meters, such as secondary customers on Rate Schedule LPL, a similar calculation is used utilizing appropriate profiled summer on-peak load factors. The lower of the resulting customer peak load estimate or the summer on-peak measured demand will then be used. For hourly customers such as Rate Schedule HTS, the average of five coincident hourly peaks will be used. The five hours will be based on the same five PJM peak hours as discussed above. If any of these hourly customers were interrupted during the five hours due to Active Load Management (ALM) events, their loads will be adjusted accordingly, or an alternate day peak load will be substituted, so that their subsequent peak is on an "unrestricted" basis. These adjustments are necessary to be consistent with the PJM and LDC loads, which are also on an "unrestricted" basis. The impact of these ALM events will be treated and tracked separately.

The second step calls for the total of these individual loads (with appropriate LDC losses added) to be compared to the PSE&G normalized summer peak load calculated by PJM (approximately 9200 MW as discussed above). A final scaling up or down is performed on each customer's peak load so that the total of the customer peaks equals the 9200 MW.

An estimated peak load will also be assigned to each new customer added since the Summer peak period is based on available information and system average values.

This information, aggregated by Supplier (including PSE&G Basic Generation Service), will be transmitted to PJM. PJM applies a reserve factor and a diversity factor to each Supplier's capacity peak load received from the LDC to determine the Supplier's capacity obligation within the PSE&G zone.

2. Customer Transmission Peak Load Determination

Each customer's transmission load/obligation is calculated using a similar method as described above for capacity. The method above is adjusted as follows: (1) the value assigned by PJM to each zone is based upon the actual load for each zone at the single highest hour of the zone load (not the weather normalized value) and (2) allocation of the transmission peak load to individual customers will be based on the five highest zonal peak loads (not the five highest PJM peak loads).

This information, supplied by the Company and aggregated by Supplier, is transmitted to PJM. No further adjustment is required by PJM.

B. CUSTOMER ENERGY - INTERCHANGE OBLIGATIONS

The PSE&G zonal hourly load of an electric generation supplier ("EGS") supplying load within PSE&G's service territory shall be the sum of the EGS's individual wholesale and retail

customer hourly loads. PSE&G shall report to PJM each day the estimated hourly loads for EGSs. On a monthly basis, PSE&G shall reconcile actual individual customer meter readings and applicable load profile data with the estimated data previously provided on a daily basis for all EGSs and report all hourly differences to PJM by EGS. Individual wholesale and retail customer ("customer") hourly loads for the PSE&G zone shall be determined as follows:

1. Customer usage will be adjusted for losses based on the customer's voltage level. Loss factors will be based on losses contained in PSE&G's then-current Tariff for Electric Service or successor tariff.

2. For hourly (interval) metered customers, the customer's telemetered hourly meter readings will be used in the determination of the customer's estimated hourly load shares. On a monthly basis, PSE&G shall reconcile actual customer meter readings and data previously used in the daily report to PJM for use in reporting any EGS hourly differences to PJM.

3. Each non-hourly metered customer will be assigned a load profile based on the customer's rate schedule for electric service.

4. For non-hourly metered customers, the customer's estimated hourly load shares will be based on the average kWh use of the assigned load profile determined daily from the readings of load research sample meters. On a monthly basis, PSE&G shall reconcile actual individual customer meter readings and applicable load profile data with the estimated hourly data reported daily to PJM. On a monthly basis, PSE&G shall report hourly differences to PJM by EGS.

5. For unmetered rate schedules, the customer's hourly load shares reported will be based on static load research profiles determined for each rate schedule. Load research profiles used for unmetered rate schedules are flat and vary seasonally by on-peak and off-peak time periods.

Information regarding loads, load share calculations, obligations, and load profiles for the PSE&G zone is available on PSE&G's web site.

ATTACHMENT M-2
(ATLANTIC CITY ELECTRIC COMPANY):

PROCEDURES FOR DETERMINATION OF
PEAK LOAD CONTRIBUTIONS AND
HOURLY LOAD OBLIGATIONS FOR RETAIL CUSTOMERS

These calculations are performed on an annual basis and are fixed until the rollover to the new summer data occurs. A complete description of the procedures, together with examples and details on customer load profiles and customer classes, is maintained at Atlantic's web site, www.conectiv.com.

DETERMINATION OF CUSTOMER CAPACITY PEAK LOAD CONTRIBUTIONS

The annual calculation of Customer Capacity Peak Load Contributions (Capacity PLC) is a two-step process: (1) compute the Customer Peak Load Contributions, and (2) scale the Customer PLC's so that they sum to the allocated PJM zonal peak.

1. Five hours of customer loads are gathered, coincident with the time of PJM's five highest daily peak demands during the summer peak. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour quantities for the billing cycles in which the five daily PJM peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage. Using industry standard profiling techniques, and grouped by rate class, weather-normalized kilowatt-hour usage in the five peak load hours is determined for these demand-metered and monthly-metered customers.

2. Interval-metered customer loads are weather normalized if their profiled usage is weather sensitive. Non-interval metered customer loads are scaled according to local weather patterns.

3. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

4. The customer loads are then scaled so that the totals for the Atlantic zone matches the Atlantic unrestricted weather-normalized zonal peak on each of the five PJM (unrestricted) peak load days. The arithmetic average of these (unrestricted) hourly values for the five PJM peak hours is the Customer's Capacity PLC. These Capacity PLC's are again scaled so that the sum of all Customer Capacity PLC's equals the zonal peak allocated by PJM.

Atlantic will aggregate the customer Capacity PLC's daily, by Supplier, and report the data to PJM, as well as make it available to the retail customers. Until individual data is available, new customers are assigned a Capacity PLC according to their profile class.

DETERMINATION OF CUSTOMER NETWORK PEAK LOAD CONTRIBUTIONS

Each customer's Network Peak Load Contribution (Network PLC) is calculated using a method similar to the two-step approach for determining Capacity PLC's. However, instead of using PJM determinants, the hourly loads are associated with the five highest (unrestricted) peaks for the Atlantic zone.

1. For retail customers, five hours of loads are gathered, coincident with the time of the five highest (unrestricted) daily peak demands for the Atlantic zone. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour usage for the billing cycles in which the five daily peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage.

2. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

3. The customer loads are then scaled so their total on each of the five days matches the corresponding unrestricted Atlantic zonal peaks.

4. The arithmetic average of the hourly values at the time of the five Atlantic daily peaks is defined as the customer's Network PLC. These values are again scaled so that the sum of all customers Network PLC's equals the retail portion of the annual Atlantic zonal peak.

Atlantic will aggregate the customer Network PLC's daily, by Supplier, and report the data to PJM on a timetable established by PJM. Until individual data is available, new customers are assigned an average Network PLC for the customer's load profile class.

DETERMINATION OF HOURLY ENERGY OBLIGATIONS

Hourly energy obligations also are addressed in a two-step process. In Settlement A, Atlantic will determine the "day after" energy responsibility. The load characteristics of the operating day in question will be recreated using the known, preliminary, and historically based information available.

1. Preliminary daily read hourly interval meter data will be adjusted for losses using established loss factors, with totals reported for each Supplier.

2. For groups of customers, who do not have interval metering, Atlantic's load profiles will be adjusted to account for factors such as weather and losses. The adjusted profiles will be applied to the profiled customers based on rate class. The assigned profile shall be scaled by customer usage factors, which are based on historical customer energy consumption. These results will be compiled by rate class and Supplier.

3. The aggregate load value for all the adjusted profiled and adjusted interval metered loads will be scaled so that the sum of all hourly loads in the Atlantic zone equals the metered zonal load.

Atlantic will aggregate the hourly energy obligations, by Supplier, and report the totals to PJM as their "day after responsibility".

Settlement B occurs after all actual monthly energy usage data has been processed for the day in question (approximately 45 − 60 days later) and occurs between the Supplier and PJM.

1. Atlantic will calculate the difference between the final hourly load obligation and the "day after" estimated load obligation previously determined in Settlement A.

2. After a calendar month becomes fully metered, Atlantic will compute and submit to PJM the complete hourly adjustments for that month.

Atlantic will aggregate the hourly energy adjustments, by Supplier, and submit to PJM a calendar-month file containing Supplier hourly energy obligation amounts. PJM will then issue a final bill reflecting any adjustments.

If any adjustments need to be made to a customer's data after the regular monthly reconciliation in Settlement B, then the Parties involved will agree on the adjustment. Atlantic will then forward the information to PJM. PJM will place the final adjustments on the appropriate Party's bill. Any disputes shall be resolved through the PJM Dispute Resolution Process.

ATTACHMENT M-2
(DELMARVA POWER & LIGHT COMPANY):

PROCEDURES FOR DETERMINATION OF
PEAK LOAD CONTRIBUTIONS AND
HOURLY LOAD OBLIGATIONS FOR RETAIL CUSTOMERS

These calculations are performed on an annual basis and are fixed until the rollover to the new summer data occurs. A complete description of the procedures, together with examples and details on customer load profiles and customer classes, is maintained at Delmarva's web site, www.conectiv.com.

DETERMINATION OF CUSTOMER CAPACITY PEAK LOAD CONTRIBUTIONS

The annual calculation of Customer Capacity Peak Load Contributions (Capacity PLC) is a two-step process: (1) compute the Customer Peak Load Contributions, and (2) scale the Customer PLC's so that they sum to the allocated PJM zonal peak.

1. Five hours of customer loads are gathered, coincident with the time of PJM's five highest daily peak demands during the summer peak. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour quantities for the billing cycles in which the five daily PJM peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage. Using industry standard profiling techniques, and grouped by rate class, weather-normalized kilowatt-hour usage in the five peak load hours is determined for these demand-metered and monthly-metered customers.

2. Interval-metered customer loads are weather normalized if their profiled usage is weather sensitive. Non-interval metered customer loads are scaled according to local weather patterns.

3. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

4. The customer loads are then scaled so that the total for the Delmarva zone matches the Delmarva unrestricted weather-normalized zonal peak on each of the five PJM (unrestricted) peak load days. The arithmetic average of these (unrestricted) hourly values for the five PJM peak hours is the Customer's Capacity PLC. These Capacity PLC's are again scaled so that the sum of all Customer Capacity PLC's equals the zonal peak allocated by PJM.

Delmarva will aggregate the customer Capacity PLC's daily, by Supplier, and report the data to PJM, as well as make it available to the retail customers. Until individual data is available, new customers are assigned a Capacity PLC according to their profile class.

DETERMINATION OF CUSTOMER NETWORK PEAK LOAD CONTRIBUTIONS

Each customer's Network Peak Load Contribution (Network PLC) is calculated using a method similar to the two-step approach for determining Capacity PLC's. However, instead of using PJM determinants, the hourly loads are associated with the five highest (unrestricted) peaks for the Delmarva zone.

1. For retail customers, five hours of loads are gathered, coincident with the time of the five highest (unrestricted) daily peak demands for the Delmarva zone. Actual metered loads for (hourly) interval-metered customer are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour usage for the billing cycles in which the five daily peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage.

2. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

3. The customer loads are then scaled so their total on each of the five days matches the corresponding unrestricted Delmarva zonal peaks.

4. The arithmetic average of the hourly values at the time of the five Delmarva daily peaks is defined as the customer's Network PLC. These values are again scaled so that the sum of all customer Network PLC's equals the retail portion of the annual Delmarva zonal peak.

Delmarva will aggregate the customer Network PLC's daily, by Supplier, and report the data to PJM on a timetable established by PJM. Until individual data is available, new customers are assigned an average Network PLC for the customer's load profile class.

DETERMINATION OF HOURLY ENERGY OBLIGATIONS

Hourly energy obligations are addressed in a two-step process. In Settlement A, Delmarva will determine the "day after" energy responsibility. The load characteristics of the operating day in question will be recreated using the known, preliminary, and historically based information available.

1. Preliminary daily read hourly interval meter data will be adjusted for losses using established loss factors, with totals reported for each Supplier.

2. For groups of customers, who do not have interval metering, Delmarva's load profiles will be adjusted to account for factors such as weather and losses. The adjusted profiles will be applied to the profiled customers based on rate class. The assigned profile shall be scaled by customer usage factors, which are based on historical customer energy consumption. These results will be compiled by rate class and Supplier.

3. The aggregate load value for all the adjusted profiled and adjusted interval metered loads will be scaled so that the sum of all hourly loads in the Delmarva zone equals the metered zonal load.

Delmarva will aggregate the hourly energy obligations, by Supplier, and report the totals to PJM as their "day after responsibility".

Settlement B occurs after all actual monthly energy usage data has been processed for the day in question (approximately 45 − 60 days later) and occurs between the Supplier and PJM.

1. Delmarva will calculate the difference between the final hourly load obligation and the "day after" estimated load obligation previously determined in Settlement A.

2. After a calendar month becomes fully metered, Delmarva will compute and submit to PJM the complete hourly adjustments for that month.

Delmarva will aggregate the hourly energy adjustments, by Supplier, and submit to PJM a calendar-month file containing Supplier hourly energy obligation amounts. PJM will then issue a final bill reflecting any adjustments.

If any adjustments need to be made to a customer's data after the regular monthly reconciliation in Settlement B, then the Parties involved will agree on the adjustment. Delmarva will then forward the information to PJM. PJM will place the final adjustments on the appropriate Party's bill. Any disputes shall be resolved through the PJM Dispute Resolution Process.

ATTACHMENT M-2
(DELMARVA POWER & LIGHT COMPANY)~~:~~

PROCEDURES FOR DETERMINATION OF PEAK LOAD CONTRIBUTIONS AND HOURLY LOAD OBLIGATIONS FOR RETAIL CUSTOMERS

These calculations are performed on an annual basis and are fixed until the rollover to the new summer data occurs. A complete description of the procedures, together with examples and details on customer load profiles and customer classes, is maintained at Delmarva's web site, www.conectiv.com.

DETERMINATION OF CUSTOMER CAPACITY PEAK LOAD CONTRIBUTIONS

The annual calculation of Customer Capacity Peak Load Contributions (Capacity PLC) is a two-step process: (1) compute the Customer Peak Load Contributions, and (2) scale the Customer PLC's so that they sum to the allocated PJM zonal peak.

1. Five hours of customer loads are gathered, coincident with the time of PJM's five highest daily peak demands during the summer peak. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour quantities for the billing cycles in which the five daily PJM peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage. Using industry standard profiling techniques, and grouped by rate class, weather-normalized kilowatt-hour usage in the five peak load hours is determined for these demand-metered and monthly-metered customers.

2. Interval-metered customer loads are weather normalized if their profiled usage is weather sensitive. Non-interval metered customer loads are scaled according to local weather patterns.

3. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

4. The customer loads are then scaled so that the total for the Delmarva zone matches the Delmarva unrestricted weather-normalized zonal peak on each of the five PJM (unrestricted) peak load days. The arithmetic average of these (unrestricted) hourly values for the five PJM peak hours is the Customer's Capacity PLC. These Capacity PLC's are again scaled so that the sum of all Customer Capacity PLC's equals the zonal peak allocated by PJM.

Delmarva will aggregate the customer Capacity PLC's daily, by Supplier, and report the data to PJM, as well as make it available to the retail customers. Until individual data is available, new customers are assigned a Capacity PLC according to their profile class.

DETERMINATION OF CUSTOMER NETWORK PEAK LOAD CONTRIBUTIONS

Each customer's Network Peak Load Contribution (Network PLC) is calculated using a method similar to the two-step approach for determining Capacity PLC's. However, instead of using PJM determinants, the hourly loads are associated with the five highest (unrestricted) peaks for the Delmarva zone.

1. For retail customers, five hours of loads are gathered, coincident with the time of the five highest (unrestricted) daily peak demands for the Delmarva zone. Actual metered loads for (hourly) interval-metered customer are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour usage for the billing cycles in which the five daily peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage.

2. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

3. The customer loads are then scaled so their total on each of the five days matches the corresponding unrestricted Delmarva zonal peaks.

4. The arithmetic average of the hourly values at the time of the five Delmarva daily peaks is defined as the customer's Network PLC. These values are again scaled so that the sum of all customer Network PLC's equals the retail portion of the annual Delmarva zonal peak.

Delmarva will aggregate the customer Network PLC's daily, by Supplier, and report the data to PJM on a timetable established by PJM. Until individual data is available, new customers are assigned an average Network PLC for the customer's load profile class.

DETERMINATION OF HOURLY ENERGY OBLIGATIONS

Hourly energy obligations are addressed in a two-step process. In Settlement A, Delmarva will determine the "day after" energy responsibility. The load characteristics of the operating day in question will be recreated using the known, preliminary, and historically based information available.

1. Preliminary daily read hourly interval meter data will be adjusted for losses using established loss factors, with totals reported for each Supplier.

2. For groups of customers, who do not have interval metering other interval meters which are not read daily, Delmarva's load profiles will be adjusted to account for factors such as weather and losses. The adjusted profiles will be applied to the profiled customers based on rate class. The assigned profile shall be scaled by customer usage factors, which are based on historical customer energy consumption. These results will be compiled by rate class and Supplier.

3. The aggregate load value for all the adjusted profiled and adjusted interval metered loads will be scaled so that the sum of all hourly loads in the Delmarva zone equals the metered zonal load.

Delmarva will aggregate the hourly energy obligations, by Supplier, and report the totals to PJM as their "day after responsibility".

Settlement B occurs after all actual monthly energy usage data has been processed for the day in question (approximately 45 − 60 days later) and occurs between the Supplier and PJM.

1. Delmarva will calculate the difference between the final hourly load obligation and the "day after" estimated load obligation previously determined in Settlement A.

2. After a calendar month becomes fully metered, Delmarva will compute and submit to PJM the complete hourly adjustments for that month.

Delmarva will aggregate the hourly energy adjustments, by Supplier, and submit to PJM a calendar-month file containing Supplier hourly energy obligation amounts. PJM will then issue a final bill reflecting any adjustments.

If any adjustments need to be made to a customer's data after the regular monthly reconciliation in Settlement B, then the Parties involved will agree on the adjustment. Delmarva will then forward the information to PJM. PJM will place the final adjustments on the appropriate Party's bill. Any disputes shall be resolved through the PJM Dispute Resolution Process.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider or ILR Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

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

2.4 Base Offer Segment

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

2.5 Base Residual Auction

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

2.6 Buy Bid

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

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a PJM Member that has the capability to reduce load, or that aggregates customers capable of reducing load. The Demand Resource Provider shall notify the Office of the Interconnection whether such load reduction is provided by a Limited Demand Resource, Extended Summer Demand Resource or an Annual Demand Resource. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource.

2.23 EFORd

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

2.24 Energy Efficiency Resource

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

2.24A Extended Summer Demand Resource

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

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Extended Summer Demand Resource Reliability Target

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

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Extended Summer Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 [Reserved]

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A Final Zonal ILR Price

"Final Zonal ILR Price" shall mean the Adjusted Zonal Capacity Price after the Second Incremental Auction, less the amount paid in CTR credits per MW of load in the Zone in which the ILR is to be certified.

2.27 First Incremental Auction

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

2.28 Forecast Pool Requirement

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

2.29 Forecast RTO ILR Obligation

"Forecast RTO ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the PJM Region times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region, for use in Delivery Years through May 31, 2012.

2.30 Forecast Zonal ILR Obligation

"Forecast Zonal ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the Zone times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in such Zone, for use in Delivery Years through May 31, 2012.

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 ILR Forecast

"ILR Forecast" shall mean, for any Delivery Year ending on or before May 31, 2012, the average annual megawatt quantity of ILR certified for the five Planning Periods preceding the date of the forecast; provided, however, that before such data becomes available for five Delivery Years under the Reliability Pricing Model, comparable data on Active Load Management (as defined in the preexisting reliability assurance agreements) from up to five prior Planning Periods shall be substituted as necessary; and provided further that, for transmission zones that were integrated into the PJM Region less than five years prior to the conduct of the Base Residual Auction for the Delivery Year, data on incremental load subject to mandatory interruption by Electric Distribution Companies within such zones shall be substituted as necessary.

2.33 ILR Provider

"ILR Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as such term is defined in the PJM Operating Agreement, may be an ILR Provider, provided it obtains certification of its load reduction capability as ILR.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Interruptible Load for Reliability (ILR)

"Interruptible Load for Reliability" or "ILR" shall have the meaning specified in the Reliability Assurance Agreement.

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for the PJM Region or such LDA.

As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; and ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result. Second, PJM adopts the lower result from these two tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.37 Load Serving Entity (LSE)

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

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

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

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Short-Term Resource Procurement Target for the PJM Region in Unforced Capacity] minus [the Extended Summer Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the Short-Term Resource Procurement Target for such LDA in Unforced Capacity] minus [the LDA CETL] minus [the Extended Summer Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual

Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Short-Term Resource Procurement Target for the RTO in Unforced Capacity] minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the Short-Term Resource Procurement Target for the LDA in Unforced Capacity] minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

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

2.43A Nominated Energy Efficiency Value

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

2.44 Nominated ILR Value

"Nominated ILR Value" shall mean the amount of load reduction that an ILR resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For ILR, the maximum Nominated ILR Capacity Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the ILR is certified.

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is dispatched in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average real-time LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be dispatched independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be dispatched for such block.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 10,500 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.61 Resource Substitution Charge

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

2.61A Scheduled Incremental Auctions

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

2.62 Second Incremental Auction

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

2.63 Sell Offer

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

2.64 [Reserved for Future Use]

2.65 Self-Supply

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

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the

Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

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

2.66 Third Incremental Auction

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

2.67 Transition Adder

"Transition Adder" shall mean a component of a Sell Offer permitted for certain Capacity Market Sellers for the Transition Period, as set forth in section 17.

2.68 Transition Period

"Transition Period" shall mean the four-year period consisting of the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010.

2.69 Unforced Capacity

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

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net

Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.70 Variable Resource Requirement Curve

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

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.3A Locational UCAP Bilateral Transactions

A Member that has committed capacity through an RPM Auction for a Delivery Year may purchase Locational UCAP as replacement capacity from a Member with available uncommitted capacity for such Delivery Year in accordance with the terms of this section and the PJM Manuals. Locational UCAP may not be sold or purchased prior to the date that the final EFORD is established for such Delivery Year, and if designated to PJM by the Locational UCAP

Seller as sold prior to the Third Incremental Auction for a Delivery Year must be confirmed by the buyer prior to such Third Incremental Auction as purchased for replacement capacity, or such transaction shall be rejected. In accordance with procedures specified in the PJM Manuals, the parties to a Locational UCAP transaction must notify PJM of such transaction, which notification must specify: i) the buyer, ii) the Locational UCAP Seller, iii) the start and end dates of the transaction (which may not be retroactive), iv) the Locational UCAP amount (no less than 0.1 megawatts), v) the demand or generation resource with available uncommitted capacity that is the basis for the sale, and vi) the Locational Delivery Area in which the resource is located. The Locational UCAP Seller shall be responsible for any charges imposed under sections 7, 8, 9, 10, 11, or 13, as applicable, for such Delivery Year, with respect to the increment of capacity sold as Locational UCAP; any other settlement of charges under the Locational UCAP transaction shall be between the parties. A purchaser of Locational UCAP may not offer such capacity into an RPM Auction.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, in accordance with the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Annual Demand Resource, Extended Summer Demand Resource, Limited Demand Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered. The Office of the Interconnection shall, in both cases, convert such value to an Unforced Capacity basis by multiplying such value by the DR Factor times the Forecast Pool Requirement. Demand Resources shall specify the LDA in which the Demand Resource is located, including the

location of such resource within any Zone that includes more than one LDA as identified on Schedule 10.1 of the RAA.

e) A Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Attachment Q to this Tariff, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Section 6.6 of Attachment DD, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

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 Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter 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.

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: [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 Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- 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 Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; 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 Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

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 Reliability Council 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 EMAAC, SWMAAC and MAAC 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, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $112,868 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")	122,040
BGE, PEPCO ("CONE Area 2")	112,868
AEP, Dayton, ComEd, APS, DQL, ATSI ("CONE Area 3")	115,479
PPL, MetEd, Penelec ("CONE Area 4")	112,868
Dominion ("CONE Area 5")	112,868

B) Beginning with the 2013-2014 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.

(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 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 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 Market 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 transmission zone in which such 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) Adjustment to Net Energy and Ancillary Services Revenue Offset

Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the

applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.

vii) 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.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Attachment M and Attachment - M Appendix to this Tariff and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) By no later than 90 days (or such other time period as established for purposes of the Transition Period) prior to the conduct of the Base Residual Auction and each Incremental Auction for such Delivery Year, the Office of the Interconnection shall post or continue to post the results of the Market Monitoring Unit's application of the Preliminary Market Structure Screen determined pursuant to section II.D of Attachment M - Appendix.

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Tests

(a) Preliminary Market Structure Screen.

The Market Monitoring Unit shall apply the Preliminary Market Structure Screen pursuant to section II.D of Attachment M - Appendix. Potential Capacity Market Sellers owning or controlling any existing Generation Capacity Resources in the PJM Region shall be required to provide to the Market Monitoring Unit the additional information specified in section II.D of Attachment M - Appendix if such Generation Capacity is located in an LDA, "Unconstrained

LDA Group" (as defined in Attachment M - Appendix), or the entire PJM Region that fails the Preliminary Market Structure Screen, as applied pursuant to section II.D below.

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or priced based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW-day of installed capacity, applicable to price-quantity offers within the Base Offer Segment for an existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW of unforced capacity. During the first three Delivery Years of the Transition Period, the Market Seller Offer Cap shall be increased for Sell Offers submitted by eligible Capacity Market Sellers in any Unconstrained LDA Group by the Transition Adder set forth in section 17.5 of this Attachment. The Market Seller Offer Cap for an existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in section II.E.3 of Attachment M- Appendix.

(b) For each existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the level of the Market Seller Offer Cap applicable to each resource. The Capacity Market Seller must promptly address any concerns identified by the

Market Monitoring Unit regarding the data and documentation provided, review the proposed Market Seller Offer Cap, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap.

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section II.E of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the level of a Market Seller Offer Cap, the Office of the Interconnection shall make its own determination of the level of the Market Seller Offer Cap based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits a Sell Offer that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the level of the Market Seller Offer Cap, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit a Sell Offer consistent with the Office of the Interconnection's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit a Sell Offer consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.E of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit a Sell Offer that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.4 and in section II.E of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) For any Third Incremental Auction, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to paragraph (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the deadline for submission of such offers in the applicable auction. Such resources are Existing Generation Capacity Resources in the auctions for any Delivery Year following the Delivery Year for which such resource cleared an RPM Auction. Such resources may receive certain price assurances for the two Delivery Years immediately following the first Delivery Year of service under certain conditions as set forth in section 5.14 of this Attachment. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

(B) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) submitted for the first year in which such resources qualify as Planned Generation Capacity Resources shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding

the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold. The Office of the Interconnection then shall clear the auction with such revised Sell Offer in place.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Section 5.6.6 of Attachment DD of the Tariff. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in Section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Section II.C.1 of Attachment M – Appendix of the Tariff, but is omitted

therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the maximum EFORd applicable to each resource. The maximum EFORd that may be used in a Sell Offer for Base Residual Auctions, First Incremental Auctions and Second Incremental Auctions, and for Conditional Incremental Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction. The maximum EFORd that may be used in a Sell Offer for Third Incremental Auctions, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the proposed maximum EFORd, and attempt to reach agreement with the Market Monitoring Unit on the maximum level of the EFORd

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below and section II.E of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the EFORd, the Office of the Interconnection shall make its own determination of the maximum level of the EFORd based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits an EFORd that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the maximum level of the EFORd, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.C of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.6 and in section II.C of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction.However, generation resource may qualify for an exception to the must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the must-offer requirement shall first submit such request to the Market Monitoring Unit for evaluation. A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD and the Office of the Interconnection agrees with this determination, or, (ii) the potential Capacity Market Seller and the Market Monitoring Unit cannot come to agreement on whether a Generation Capacity Resource should be removed from PJM Capacity Resource status or satisfied the criteria for an exception to the must-offer requirement, the potential Capacity Market Seller has submitted its request to remove the resource from PJM Capacity Resource status to the Office of the Interconnection, and the Office of the Interconnection has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of Section 6.6.

After the Market Monitoring Unit has made its determination of whether a resource has satisfied the must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Section II.C.4 of Attachment M – Appendix, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved or denied by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit that it disagrees with the Market Monitoring Unit's determination. After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the must-offer requirement and prior to the date on which bidding commences for the applicable RPM Auction, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis

of an identified exception. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Attachment M and Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the must-offer requirement, into an RPM

Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit no later than four months prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that fails the Preliminary Market Structure Screen (or, if such region fails the screen, potential auction participants in the entire PJM Region) shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than two months prior to the conduct of such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. Any Sell Offer submitted in any auction that is inconsistent with any commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required promptly to resubmit a Sell Offer that complies with such commitments. If the Capacity Market Seller does not timely resubmit its Sell Offer, it shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default price equal to the maximum price for the class of resource determined under section (c)(ii) above. The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 and section II.H of Attachment M - Appendix. The default Avoidable Cost Rates referenced in section (c)(ii) above are as set forth in the tables below for any auction conducted after September 1, 2009 for any Delivery Year through the 2012-2013 Delivery Year. To determine the default ACR values for the 2013-2014 and subsequent Delivery Years, the Office of the Interconnection shall multiply the ACR values for the immediately preceding Delivery Year by a factor equal to the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission, as calculated by the Office of the Interconnection and posted to its Web site; provided, however, that after the Handy-Whitman indexing methodology has been employed to determine the default ACR values for the RPM Auctions for three consecutive Delivery Years, the Office of the Interconnection shall: i) review the default ACR values to determine whether any changes other than those produced by such methodology are warranted for subsequent Delivery Years (including seeking the analysis and advice of the Market Monitoring Unit on such matter) and report its conclusions to the Members in writing no later than four months after the Base Residual Auction for the third such Delivery Year; and ii) file with FERC resulting changes, if any, to this section no later than seven months after such Base Residual Auction, to be effective for the Base Residual Auction for the following Delivery Year; provided further, that nothing herein precludes the Office of the Interconnection from filing with FERC changes to the default ACR values or any other provision of this section prior to the deadline stated in the previous clause, or at any other time. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

Technology Classes Not Likely to be the Marginal Price Setting Resource						
Technology	**2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)**	**2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)**	**2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)**	**2012 -2013 Retirement Avoidable Cost Rate ($/MW-Day)**
Nuclear	N/a	N/a	N/a	N/a	N/a	N/a
Pumped Storage	$20.77	$29.17	$21.72	$30.50	$22.71	$31.89
Hydro	$71.01	$92.87	$74.24	$97.10	$77.62	$101.52
Sub-Critical Coal	$170.48	$188.98	$178.24	$197.58	$186.35	$206.57
Super Critical Coal	$176.13	$192.65	$184.15	$201.42	$192.53	$210.59
Waste Coal - Small	$224.83	$272.31	$235.06	$284.70	$245.75	$297.65
Waste Coal – Large	$83.15	$100.45	$86.94	$105.02	$90.89	$109.80
Wind	N/a	N/a	N/a	N/a	N/a	N/a

Maximum Avoidable Cost Rates by Technology Class

Technology	2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)	2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)	2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)	2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)	2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)	2012-2013 Retirement Avoidable Cost Rate ($/MW-Day)
CC- 2 on 1 Frame F	$30.92	$43.86	$32.33	$45.85	$33.80	$47.94
CC- 3 on 1 Frame E/Siemens	$34.33	$46.48	$35.89	$48.60	$37.52	$50.81
CC – 3 or More on 1 or More Frame F	$26.76	$37.16	$27.98	$38.85	$29.26	$40.62
CC-NUG Cogen. Frame B or E Technology	$114.93	$154.43	$120.16	$161.45	$125.62	$168.80
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$24.57	$32.68	$25.69	$34.17	$26.86	$35.73
CT - 1st & Gen. Frame B	$24.28	$32.41	$25.38	$33.87	$26.54	$35.42
CT - 2nd Gen. Frame E	$23.08	$30.89	$24.13	$32.29	$25.23	$33.76
CT - 3rd Gen. Aero (GE LM 6000)	$55.87	$82.36	$58.42	$86.10	$61.07	$90.02
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$29.30	$43.20	$30.64	$45.17	$32.03	$47.23
CT - 3rd Gen. Frame F	$23.69	$34.12	$24.77	$35.68	$25.90	$37.30
Diesel	$26.29	$33.39	$27.49	$34.91	$28.74	$36.49
Oil and Gas Steam	$65.21	$79.39	$68.18	$83.01	$71.28	$86.78

After the Market Monitoring Unit conducts its annual review of the table of default Avoided Cost Rates included in section 6.7(c) above in accordance with the procedure specified in section II.H of Attachment M – Appendix, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file its values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit relevant cost data concerning each data item specified as set forth in section 6. If cost data is not available at the time of submission for the time periods specified in section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate. The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(c) below.

iii. Projected PJM Market Revenues, as defined by section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, a Capacity Market Seller must timely submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-

Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

    - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

    - **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

    - **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

    - **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

    - **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve

months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

- **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 16 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. A Sell Offer submitted in the BRA for either or both of the 2007-2008 and 2008-2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the

clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Year Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Year Plus Option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under section 5.14(c) of this Attachment.

- ARPIR (Avoidable Refunds of Project Investment Reimbursements) consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Part V, Section 118 of this Tariff or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Part V, Section 119 of the Tariff and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

ATTACHMENT II

MTEP PROJECT COST RECOVERY FOR ATSI ZONE

I. Definitions

A. ATSI - American Transmission Systems, Incorporated.

B. Midwest ISO or MISO – The Midwest Independent Transmission System Operator, Inc.

C. Midwest ISO Tariff - The Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff.

D. [Reserved]

E. MTEP – The Midwest ISO Transmission Expansion Plan established pursuant to Attachment FF of the Midwest ISO Tariff.

F. MTEP Project – A transmission project constructed by ATSI pursuant to Attachment FF of the Midwest ISO Tariff. For purposes of this Attachment II, MTEP Projects are limited to those projects listed in Section V of this Attachment.

II. Introduction and Purpose

This Attachment II addresses the manner in which the Office of the Interconnection will distribute revenues received from the Midwest ISO for MTEP Projects constructed by ATSI.

III. [Reserved]

IV. ATSI MTEP Project Revenue Requirements Allocated to Midwest ISO Zones

A. Derivation of Annual Revenue Requirements

Under the methodology provided under Attachment H–21 to this Tariff, ATSI will periodically update the annual revenue requirements for MTEP Projects constructed by ATSI. No later than May 1 each year, ATSI shall provide these updated revenue requirements to the Midwest ISO for the upcoming June 1 – May 31 rate year. The list of MTEP Projects for purposes of this Section IV.A is provided in Section V.B.

B. Allocation of Annual Revenue Requirements to Midwest ISO Zones

The portion of the annual revenue requirements derived under Section IV.A that will be recovered from transmission customers taking transmission service in the Midwest ISO shall be calculated by the Midwest ISO by multiplying each MTEP Project's revenue requirements derived in Section IV.A by the percentage allocable to each applicable Midwest ISO zone in accordance with the allocation methodology approved by FERC

with respect to that MTEP Project, at the time the project was approved by the Midwest ISO Board of Directors.

C. Monthly Revenue Requirements Owed from the Midwest ISO Zones

Each month, and pursuant to agreed upon settlement procedures, the Midwest ISO shall remit an amount to the Office of the Interconnection from revenues collected by the Midwest ISO in proportion to ATSI's annual pro-rata share of the total Network Upgrade Charge as described in the Midwest ISO Schedule 26.

D. Revenue Distribution from Payments Made by Transmission Customers in the Midwest ISO

Provided the Midwest ISO remits to the Office of the Interconnection the amount of revenue requirements owed ATSI pursuant to Section IV.C, PJM shall credit 100% of the amounts to ATSI.

V. MTEP Projects

A. [Reserved]

B. MTEP Projects Constructed by ATSI

Projects ID – Project Name

890 - North Medina 345/138 kV Substation

1326- Capacitor Banks at Harding and Juniper 345 kV

AMENDED AND RESTATED
OPERATING AGREEMENT
OF
PJM INTERCONNECTION, L.L.C.

AMENDED AND RESTATED
OPERATING AGREEMENT
OF
PJM INTERCONNECTION, L.L.C.

This Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of this 2nd day of June, 1997, amends and restates as of the Effective Date the Operating Agreement of PJM Interconnection, L.L.C. filed with the FERC on April 2, 1997, as amended.

WHEREAS, certain of the Members have previously entered into an agreement, originally dated September 26, 1956, as amended and supplemented up to and including December 31, 1996, stating "their respective rights and obligations with respect to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems" (such agreement as amended and supplemented being referred to as the "Original PJM Agreement"), and which coordinated operations and interchange came to be known as the PJM Interconnection; and

WHEREAS, pursuant to a resolution of June 16, 1993, an unincorporated association comprised of the parties to the Original PJM Agreement was formed for the purpose of implementation of the Original PJM Agreement as it then existed and as it subsequently has been amended and supplemented, such association being known as the "PJM Interconnection Association"; and

WHEREAS, because of changes in federal law and policy, the Original PJM Agreement, together with other documents and agreements, was amended, restated and submitted to FERC on December 31, 1996 to restructure fundamental aspects of the operation of the Interconnection; and

WHEREAS, so that the provisions of the Original PJM Agreement could be placed into effect consistent with a February 28, 1997 order of FERC, including those provisions related to the governance of the Interconnection, the parties to the Original PJM Agreement, along with the other interested parties, approved the conversion of the PJM Interconnection Association into the LLC pursuant to the provisions of the Delaware Limited Liability Company Act, as amended (the "Delaware LLC Act"), pursuant to a Certificate of Formation (the "Certificate of Formation") and a Certificate of Conversion (the "Certificate of Conversion"), each filed with the Delaware Secretary of State (the "Recording Office") on March 31, 1997; and

WHEREAS, the Members wish to amend and restate the Operating Agreement of PJM Interconnection, L.L.C. adopted in connection with the formation of the LLC and as in effect immediately prior to the Effective Date in the form set forth below; and

WHEREAS, the Members intend to form an Independent System Operator in accordance with the regulations of the Federal Energy Regulatory Commission; and

WHEREAS, the Members wish to amend and restate the Operating Agreement to provide for expansion of the operations of PJM Interconnection, L.L.C. into additional Control Areas.

Now, therefore, in consideration of the foregoing, and of the covenants and agreements hereinafter set forth, the Members hereby agree as follows:

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5.5 Distribution of Total Transmission Loss Charges.

The total Transmission Loss Charges accumulated by ~~the Office of Interconnection~~ PJMSettlement in any hour shall be distributed pro-rata to each Network Service User and Transmission Customer in proportion to its ratio shares of the total MWhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, or the total exports of MWh of energy from the PJM Region (that paid for transmission service during such hour). Exports of energy for which Non-Firm Point-to-Point Transmission Service was utilized and for which the Non-Firm Point-to-Point Transmission Service rate was paid will receive an allocation of the total Transmission Loss Charges based on a percentage of the MWh of energy exported on such service, determined by the ratio of Non-Firm Point-to-Point Transmission Service rate to Firm Point-to-Point Transmission Service rate.

ARTICLE 1 -- DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

1.1 Agreement

Agreement shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

1.1A Annual Demand Resource

Annual Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1 .2 Applicable Regional Reliability Council

Applicable Regional Reliability Council shall have the same meaning as in the PJM Tariff.

1.3 Base Residual Auction

Base Residual Auction shall have the same meaning as in Attachment DD to the PJM Tariff.

1.4 Behind The Meter Generation

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

1.5 Black Start Capability

Black Start Capability shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

1.6 Capacity Emergency Transfer Objective ("CETO")

Capacity Emergency Transfer Objective ("CETO") shall mean the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be calculated based in part on EFORD determined in accordance with Paragraph C of Schedule 5.

1.7 Capacity Emergency Transmission Limit ("CETL")

Capacity Emergency Transmission Limit ("CETL") shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

1.8 Capacity Resources

Capacity Resources shall mean megawatts of (i) net capacity from existing or Planned Generation Capacity Resources meeting the requirements of Schedules 9 and 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under this Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from existing or Planned Generation Capacity Resources within the PJM Region not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10; and (iii) load reduction capability provided by Demand Resources, Energy Efficiency Resources, or ILR that are accredited to the PJM Region pursuant to the procedures set forth in Schedule 6.

1.9 Capacity Transfer Right

Capacity Transfer Right shall have the meaning specified in Attachment DD to the PJM Tariff.

1.10 Control Area

Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and Applicable Regional Reliability Councils;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.11 Daily Unforced Capacity Obligation

Daily Unforced Capacity Obligation shall have the meaning set forth in Schedule 8 or, as to an FRR Entity, in Schedule 8.1.

1.12 Delivery Year

Delivery Year shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Attachment DD to the Tariff or pursuant to an FRR Capacity Plan.

1.13 Demand Resource

Demand Resource or "DR" shall mean a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan. As set forth in Schedule 6, a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may be an existing demand response resource or a Planned Demand Resource.

1.14 Demand Resource Provider

Demand Resource Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.15 DR Factor

DR Factor shall mean that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource or ILR in accordance with Schedule 6.

1.16 East RAA

East RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM Region, PJM Rate Schedule FERC No. 27.

1.17 Electric Cooperative

Electric Cooperative shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

1.18 Electric Distributor

Electric Distributor shall mean an entity that owns or leases with rights equivalent to ownership electric distribution facilities that are providing electric distribution service to electric load within the PJM Region.

1.19 Emergency

Emergency shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

1.20 End-Use Customer

End-Use Customer shall mean a Member that is a retail end-user of electricity within the PJM Region.

1.20A Energy Efficiency Resource

Energy Efficiency Resource shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Schedule 6 of this Agreement and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described in Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

1.20B Existing Generation Capacity Resource

Existing Generation Capacity Resource shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

1.20C Extended Summer Demand Resource

Extended Summer Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.21 Facilities Study Agreement

Facilities Study Agreement shall have the same meaning as in the PJM Tariff

1.22 FERC

FERC shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department.

1.23 Firm Point-To-Point Transmission Service

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

1.24 Firm Transmission Service

Firm Transmission Service shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

1.25 Fixed Resource Requirement Alternative or FRR Alternative

Fixed Resource Requirement Alternative or FRR Alternative shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in Schedule 8.1 to this Agreement.

1.26 Forecast Pool Requirement

Forecast Pool Requirement shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.27 Forecast RTO ILR Obligation

Forecast RTO ILR Obligation shall have the same meaning as in the PJM Tariff.

1.28 Forecast Zonal ILR Obligation

Forecast Zonal ILR Obligation shall have the same meaning as in the PJM Tariff.

1.29 FRR Capacity Plan

FRR Capacity Plan shall mean a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in Schedule 8.1 to this Agreement.

1.30 FRR Entity

FRR Entity shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

1.31 FRR Service Area

FRR Service Area shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load

(including load growth) within such area excluding the load of Single-Customer LSEs that are FRR Entities. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

1.32 Full Requirements Service

Full Requirements Service shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.33 Generation Capacity Resource

Generation Capacity Resource shall mean a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of this Agreement. A Generation Capacity Resource may be an *E*xisting Generation Capacity Resource or a Planned Generation Capacity Resource.

1.34 Generation Owner

Generation Owner shall mean a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

1.35 Generator Forced Outage

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

1.36 Generator Maintenance Outage

Generator Maintenance Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

1.37 Generator Planned Outage

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

1.38 Good Utility Practice

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

1.39 ILR Provider

ILR Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.40 Incremental Auction

Incremental Auction shall mean the First Incremental Auction, the Second Incremental Auction, the Third Incremental Auction, or the Conditional Incremental Auction, each as defined in Attachment DD to the PJM Tariff.

1.41 Interconnection Agreement

Interconnection Agreement shall have the same meaning as in the PJM Tariff.

1.42 Interruptible Load for Reliability, or ILR

Interruptible Load for Reliability, or ILR, shall mean a resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that is certified by PJM no later than three months prior to a Delivery Year. At a minimum, ILR shall be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the ILR shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time in the corresponding Delivery Year.

1.43 IOU

IOU shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

1.43A Limited Demand Resource

Limited Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.44 Load Serving Entity or LSE

Load Serving Entity or LSE shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

1.45 Locational Reliability Charge

Locational Reliability Charge shall mean the charge determined pursuant to Schedule 8.

1.46 Markets and Reliability Committee

Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.47 Member

Member shall mean an entity that satisfies the requirements of Sections 1.24 and 11.6 of the PJM Operating Agreement. In accordance with Article 4 of this Agreement, each Party to this Agreement also is a Member.

1.48 Members Committee

Members Committee shall mean the committee specified in Section 8 of the PJM Operating Agreement composed of the representatives of all the Members.

1.49 NERC

NERC shall mean the North American Electric Reliability Council or any successor thereto.

1.50 Network Resources

Network Resources shall have the meaning set forth in the PJM Tariff.

1.51 Network Transmission Service

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

1.52 Nominated Demand Resource Value

Nominated Demand Resource Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.53 Nominated ILR Value

Nominated ILR Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.54 Non-Retail Behind the Meter Generation

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

1.55 Obligation Peak Load

Obligation Peak Load shall have the meaning specified in Schedule 8 of this Agreement.

1.56 Office of the Interconnection

Office of the Interconnection shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

1.57 Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement

Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement shall mean that certain agreement, dated April 1, 1997 and as amended and restated June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.58 Operating Reserve

Operating Reserve shall mean the amount of generating capacity scheduled to be available for a specified period of an operating day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

1.59 Other Supplier

Other Supplier shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the PJM Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

1.60 Partial Requirements Service

Partial Requirements Service shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.61 Percentage Internal Resources Required

Percentage Internal Resources Required shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

1.62 Party

Party shall mean an entity bound by the terms of this Agreement.

1.63 PJM

PJM shall mean the PJM Board and the Office of the Interconnection.

1.64 PJM Board

PJM Board shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Operating Agreement.

1.65 PJM Manuals

PJM Manuals shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

1.66 PJM Open Access Transmission Tariff or PJM Tariff

PJM Open Access Transmission Tariff or PJM Tariff shall mean the tariff for transmission service within the PJM Region, as in effect from time to time, including any schedules, appendices, or exhibits attached thereto.

1.67 PJM Region

PJM Region shall have the same meaning as provided in the Operating Agreement.

1.68 PJM Region Installed Reserve Margin

PJM Region Installed Reserve Margin shall mean the percent installed reserve margin for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.69 Planned Demand Resource

Planned Demand Resource shall mean a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Schedule 6.

1.69A Planned External Generation Capacity Resource

Planned External Generation Capacity Resource shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Reliability Pricing Model Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has executed an interconnection agreement (functionally equivalent to a System Impact Study Agreement under the PJM Tariff for Base Residual Auction and an Interconnection Service Agreement under the PJM Tariff for Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and if applicable the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. An External Generation Capacity Resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

1.70 Planned Generation Capacity Resource

Planned Generation Capacity Resource shall mean a Generation Capacity Resource participating in the generation interconnection process under Part IV, Subpart A of the PJM Tariff, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Plan; (ii) a System Impact Study Agreement has been executed prior to the Base Residual Auction for such Delivery Year; (iii) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate; and (iv) no megawatts of capacity have cleared an RPM Auction for any prior Delivery Year. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

1.71 Planning Period

Planning Period shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

1.72 Public Power Entity

Public Power Entity shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

1.73 Qualifying Transmission Upgrades

Qualifying Transmission Upgrades shall have the meaning specified in Attachment DD to the PJM Tariff.

1.74 Markets and Reliability Committee

Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.75 Reliability Principles and Standards

Reliability Principles and Standards shall mean the principles and standards established by NERC or an Applicable Regional Reliability Council to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

1.76 Required Approvals

Required Approvals shall mean all of the approvals required for this Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of this Agreement.

1.77 Self-Supply

Self Supply shall have the meaning provided in Attachment DD to the PJM Tariff.

1.78 Single-Customer LSE

Single-Customer LSE shall mean a Party that (a) serves only retail customers that are Affiliates of such Party; (b) owns or controls generation facilities located at one or more of the retail customer location(s) that in the aggregate satisfy at least 50% of such Party's Unforced Capacity obligations; and (c) serves retail customers having (i) an Obligation Peak Load at all locations of no less than 100 MW, where such peak load of each such location is no less than 10 MW; or (ii) an Obligation Peak Load at each location served of no less than 25 MW.

1.79 South RAA

South RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM South Region, on file with FERC as PJM Rate Schedule FERC No. 40.

1.80 State Consumer Advocate

State Consumer Advocate shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.81 State Regulatory Structural Change

State Regulatory Structural Change shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or

(b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

1.82 Threshold Quantity

Threshold Quantity shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Schedule 8.1).

1.83 Transmission Facilities

Transmission Facilities shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

1.84 Transmission Owner

Transmission Owner shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.85 Transmission Owners Agreement

Transmission Owners Agreement shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005 and as amended from time to time, among transmission owners within the PJM Region.

1.86 Unforced Capacity

Unforced Capacity shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

1.87 West RAA

West RAA shall mean the "PJM West Reliability Assurance Agreement among the Load Serving Entities in the PJM West Region," on file with FERC as PJM Rate Schedule FERC No. 32.

1.88 Zonal Capacity Price

Zonal Capacity Price shall mean the price of Unforced Capacity in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year as determined pursuant to Attachment DD to the PJM Tariff.

1.89 Zone

Zone shall mean an area within the PJM Region, as set forth in Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load (as defined in the PJM Tariff) located outside the PJM Region that is served from such Zone under Schedule H-A of the PJM Tariff.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES, ILR, AND ENERGY EFFICIENCY

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

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

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

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

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

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

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

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

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

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Demand Resource Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the

location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

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

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

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

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

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

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

Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of Demand Resource and ILR above, there can be two notification periods:

Step 1 (Short Lead Time) – Demand Resource or ILR which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.

Step 2 (Long Lead Time) – Demand Resource or ILR which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

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

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

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

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

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

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

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

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource or ILR load

reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

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

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

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

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

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

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

L. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource and ILR events. The process establishes potential under/over compliance values for the Provider. Compliance will be established for each Provider on an event specific basis for the Provider's Demand Resources or ILR dispatched by the Office of the Interconnection during such event.

PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period. Compliance for Direct Load Control programs will consider only the transmission of the control signal. Providers are required to report the time period (during the Demand Resource and ILR event) that the control signal was actually sent. Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance is checked on an individual customer basis for GLD, by comparing actual load dropped during the event to the nominated amount of load drop. Providers must submit actual loads and comparison loads for the compliance hours. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

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

M. Energy Efficiency Resources

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

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of

affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value, which shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday. The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

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

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

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

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

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

SCHEDULE 8.1

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3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Synchronized, and (iv) Operating Reserve - Supplemental. Subject to the provisions of Schedules 1 through 6, the Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Provider shall administer the purchases by Transmission Customers of these Ancillary Services. PJMSettlement shall be the Counterparty to the Ancillary Services provided to the Transmission Customer; provided, however, that PJMSettlement shall not be the contracting party to bilateral transactions between market participants or with respect to a self-schedule or self-supply relating to Ancillary Services. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible. The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Service provided by the Transmission Provider in conjunction with its

provision of transmission services 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. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

7.1A Payments:

(a) Monthly Bills.

Net amounts due to PJMSettlement, in its own name or as agent for Transmission Provider, as applicable, pursuant to a monthly bill shall be due and payable by the Transmission Customer or other entity no later than noon Eastern Prevailing Time on the due date of the first weekly bill issued for activity in the month that the monthly bill is issued. It is possible, due to the timing of holidays, that the billing and payment cycle for monthly bills stated here would call for payment of a monthly bill on a Friday that occurs less than three business days after issuance of the bill by PJM. Where this occurs, the payment period of the monthly bill will be extended such that payment will be due when payment for the second weekly bill is due.

(b) Weekly Bills.

Net amounts due to PJMSettlement, in its own name or as agent for Transmission Provider, as applicable, pursuant to a weekly bill shall be due and payable by the Transmission Customer or other entity no later than noon Eastern Prevailing Time on the third business day following the issuance of the weekly bill. Weekly bills issued after 5:00 p.m. Eastern Prevailing Time shall be considered to be issued the following business day

(i) Municipal Electric Systems.

Recognizing that municipal electric systems may, at times, face unique circumstances that could temporarily prevent their ability to make payments on a weekly bill issued pursuant to Section 7.1(b) when due, the Transmission Provider may allow a municipal electric system to make arrangement with PJM whereby PJM would extend trade credit to the municipal electric system sufficient to enable it to make payment on a weekly bill provided that the following conditions are met:

(a) the Transmission Provider determines, in its sole discretion, that it has sufficient excess working capital available to complete financial settlement with other market participants;

(b) the municipal electric system reimburses PJM for the actual cost of such working capital;

(c) the municipal electric system provides PJM with a binding representation that it has all legal right and authority to enter into the arrangement with PJM;

(d) PJMSettlement will continue to issue weekly bills to the municipal electric system in accordance with Section 7,1(b) above and the municipal electric system will make payment as due under the weekly bills using the proceeds it obtains

under its arrangement with PJM. Reimbursement of these amounts, including PJM's actual costs of working capital, shall be due from the municipal electric system at the time payment is due for the invoice issued under Section 7.1A(a);

(e) the aggregate of all financed amounts and accrued obligations shall not exceed the Working Credit Limit available to the municipal electric system;

(f) the municipal electric system provides the Transmission Provider with at least one week of notice (though PJM may waive this provision), and;

(g) the accumulated duration of such postponed payments shall not exceed three months in a rolling twelve-month period.

PJM may terminate this payment option at any time it determines its excess working capital is no longer sufficient to allow further or continued extension financing. In such cases, PJM shall attempt to give five business days, but not less than three business days notice to the affected municipal electric system, and may call for immediate reimbursement of any outstanding amounts owed by the municipal electric system.

(c) Form of Payments.

All payments tendered in satisfaction of a Transmission Customer's or other entity's obligations to PJMSettlement or Transmission Provider shall be in the form of immediately available funds payable to PJMSettlement, or by wire transfer to a bank named by PJMSettlement.

(d) Payments by PJMSettlement.

Unless delayed by unforeseen events, payments made by PJMSettlement, in its own name or as agent for Transmission Provider, for amounts due to Transmission Customers and other entities shall be paid no later than 5:00 p.m. Eastern Prevailing Time on the business day following the payment due date for net amounts owed to PJMSettlement, in its own name or as agent for the Transmission Provider, as specified above.

(e) Payment Calendar.

A comprehensive billing and settlement calendar will be posted on Transmission Provider's website prior to March 31 for the upcoming June – May annual period to communicate the schedule of holidays for settlement and billing purposes.

(f) Late Payments.

In the event that a Transmission Customer, or other entity, is delinquent in paying the amount set forth in its weekly or monthly bill two or more times within any rolling twelve (12) month period, PJMSettlement, in its own name or as agent for Transmission Provider, may assess, in addition to the interest on each late payment as provided for in

Section 7.2 of this Tariff, a late payment charge for a second and any subsequent failure to pay on time during such twelve (12) month period (a "Late Payment Charge"). The applicable Late Payment Charge will be assessed in an amount equal to the greater of: (i) two percent (2%) of the total amount set forth in the monthly or weekly bill that the Transmission Customer or other entity has been late in paying, or (ii) $1,000; up to a maximum of $100,000 per late bill payment. For the sole purpose of application of this Section 7.1A(f), weekly and monthly bills that are due on the same date shall be considered to be one bill; moreover, the term "on time" shall mean payment received on the date due; and "delinquent" shall mean any payment received on a day subsequent to the date due.

Late Payment Charges that are collected pursuant to this Section 7.1A(f) shall be credited to PJMSettlement administrative costs and will be included in any applicable stated rate refund calculations as contemplated under Schedule 9 of this Tariff.

23.1 Procedures for Assignment or Transfer of Service:

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion; provided that, for service prior to October 1, 2010, compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Transmission Provider and PJMSettlement governing reassignments of transmission service prior to the date on which the reassigned service commences. PJMSettlement shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider and PJMSettlement or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider and PJMSettlement or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

29.1 Condition Precedent for Receiving Service:

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff or, with respect to a state required retail access program, provides the information required under the Service Agreement, (ii) the Eligible Customer and the Transmission Provider in coordination with the affected Transmission Owners complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F or Attachment F-1 for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

SCHEDULE 16-A

Transmission Service for Imports on the Linden VFT Facility

Pursuant to Section 38 of the Tariff, this Schedule provides the terms and conditions of transmission service for imports on the Linden VFT Facility which is a Merchant Transmission Facility under the Tariff and the Amended and Restated Operating Agreement of PJM Interconnection, L.LC ("Operating Agreement").

1. Definitions

Capitalized terms used and defined in this Schedule 16-A shall have the meaning given them under this Schedule. Capitalized terms used and not defined in this Schedule 16-A but defined in other provisions of the Tariff shall have the meaning given them under those provisions. Capitalized terms used in this Schedule 16-A that are not defined in it or elsewhere in this Tariff shall have the meanings customarily attributed to such terms by the electric utility industry in PJM, including, but not limited to the Operating Agreement.

1.1 Linden VFT Reservation: For purposes of this Schedule 16-A, a right, denoted in whole megawatts and for a specified period, to request the injection of energy and capacity into the Transmission System at the Point of Interconnection and submit schedules for transmission service utilizing the Linden VFT Facility on a firm or non-firm basis as set forth in this Schedule 16-A.

1.1.1 Firm Linden VFT Reservation: A Firm Linden VFT Reservation allows a Linden VFT Transmission Customer to schedule capacity and energy on a firm basis from the Linden VFT Point of Receipt to the Linden VFT Point of Delivery.

1.1.2 Non-Firm Linden VFT Reservation: A Non-Firm Linden VFT Reservation allows a Linden VFT Transmission Customer to schedule energy on a non-firm, as available, basis from the Linden VFT Point of Receipt to the Linden VFT Point of Delivery.

1.2 Linden VFT Transmission Customer: An entity that (i) is an Eligible Customer (or its Designated Agent) that meets the creditworthiness requirements of the Transmission Provider set forth in Attachment Q to this Tariff and is in good-standing with respect to all payments owed under the Tariff and Operating Agreement; (ii) executes a Linden VFT Service Agreement, the form of which is attached as Exhibit A to this Schedule 16-A; (iii) holds a Linden VFT Reservation, and, in the case of a re-sale of a Linden VFT Reservation, (iv) has the applicable Attachment A-1 completed and signed by all parties.

1.3 Linden VFT Facility: The Linden VFT Facility is a controllable alternating current Merchant Transmission Facility located in Linden, New Jersey, which was the subject of Commission orders in FERC Docket No. ER07-543 et al. regarding operation of these transmission facilities as a merchant transmission facility and as more particularly described in the Interconnection Service Agreement among PJM Interconnection, L.L.C. and Linden VFT,

LLC and Public Service Electric and Gas Company, which was accepted for filing by the Commission in FERC Docket No. ER06-649.

1.4 Linden VFT Schedule: The schedule for the transmission of capacity and energy on the Linden VFT Facility pursuant to the terms and conditions of service set forth in this Schedule 16-A.

1.4A Linden VFT Service: Transmission service provided pursuant to the terms and conditions of service set forth in this Schedule 16-A.

1.5 Linden VFT Transmission Owner: Linden VFT, LLC, its agents, successors or assigns.

1.6 Primary Rights Holder(s): Entities that have been allocated rights to the use of the transmission capability of the Linden VFT Facility and assigned Firm and Non-Firm Transmission Injection Rights by the Linden VFT Transmission Owner in accordance with Section 2.1. To the extent any portion of the total transmission capability of the Linden VFT Facility has not been assigned pursuant to Section 2.1 the Linden VFT Transmission Owner shall be the Primary Rights Holder of such capacity for purposes of this Schedule 16-A until such capacity is allocated to another entity.

1.7 Point of Interconnection: The Point of Interconnection is as defined in Section 11.1 of the Interconnection Service Agreement among PJM Interconnection, L.L.C. and East Coast Power, L.L.C., which was assigned to Linden VFT, LLC effective December 21, 2006, and is the Linden VFT Point of Delivery.

1.8 Linden VFT Service Agreement: An initial agreement and any amendments or supplements thereto entered into by a Linden VFT Transmission Customer and the Transmission Provider for transmission service on the Linden VFT Facility under this Schedule 16-A, the form of which is included as Exhibit A to this Schedule 16-A.

1.9 Linden VFT Point of Delivery: For purposes of this Schedule 16-A, the point of delivery is the Point of Interconnection with the 230 kV transmission line connecting Public Service Electric and Gas Company's Warinanco substation with the Tosco substation near Linden, New Jersey.

1.10 Linden VFT Point of Receipt: For purposes of this Schedule 16-A, the point of receipt is the point of connection with transmission facilities at the 345 kV Linden Cogen ring bus, which is the point for the interchange of capacity and energy between PJM and NYISO.

2. Allocation of Available Transmission Capability on the Linden VFT Facility

2.1 Commission Approved Allocation Process: The Linden VFT Transmission Owner shall allocate the total transmission capability on the Linden VFT Facility pursuant to an allocation process approved by the Commission under FERC Docket No. ER07-543-000 as such allocation process may be amended by the Linden Transmission Owner from time-to-time

subject to Commission approval provided that the results of such rights allocation process shall be furnished to the Transmission Provider and posted on the OASIS. The allocation of rights to Primary Rights Holders for the transmission capability of the Linden VFT Facility shall include the allocation of the Firm and Non-Firm Transmission Injection Rights, as applicable, which have been assigned to the Linden VFT Transmission Owner pursuant to Section 232 of this Tariff as well as the award of Firm and Non-Firm Linden VFT Reservations. The allocation of such rights shall be in the megawatt quantity and for the period specified for allocation to parties pursuant to the Linden VFT Transmission Owner's Commission-approved allocation process and as submitted to the Transmission Provider for posting on the OASIS. In the event that there has been no allocation of Firm or Non-Firm Transmission Injection Rights to a Primary Rights Holder, the Linden VFT Transmission Owner is the holder of such unallocated Firm or Non-Firm Transmission Injection Rights.

2.2 Charges for Allocation of Rights by Linden VFT Transmission Owner to Primary Rights Holder: The charges applicable to the allocation of rights to a Primary Rights Holder pursuant to this section shall be determined pursuant to arrangements between the Linden VFT Transmission Owner and the Primary Rights Holder in accordance with the process approved by the Commission under FERC Docket No. ER07-543-000, as amended by the Linden VFT Transmission Owner from time-to-time subject to Commission approval. The charge for the allocation of rights to a Primary Rights Holder shall be in accordance with the Commission's authorization for the Linden VFT Transmission Owner to charge negotiated rates (i.e., rates established pursuant to market mechanisms as recognized for merchant transmission projects and not included in Transmission Provider's Tariff rates) for the use of transmission capability over the Linden VFT Facility. Agreements between the Linden VFT Transmission Owner and a Primary Rights Holder for the allocation of rights to a Primary Rights Holder shall be considered Service Agreements under this Schedule 16-A and shall be reported by the Linden VFT Transmission Owner to the Commission through Electronic Quarterly Reports in accordance with Order No. 2001.

2.3 Transmission Injection Rights Associated with the Linden VFT Facility: The award of Transmission Injection Rights to the Linden VFT Transmission Owner shall be made pursuant to Section 232 of the Tariff and any subsequent transfer to Primary Rights Holders shall be made in accordance with Section 2.1 hereof. The Transmission Injection Rights solely allow for the injection of capacity and energy at the Point of Interconnection for the Linden VFT Facility and do not provide any priority with respect to the reservation, scheduling, curtailment or interruption of transmission service over the Linden VFT Facility pursuant to this Schedule.

2.4 Transfer of Transmission Injection Rights: Any resale, assignment, conveyance or transfer of a Transmission Injection Right shall be consistent with Section 232.6 of this Tariff and any terms and conditions agreed upon between the Linden VFT Transmission Owner and the Primary Rights Holder.

3. Linden VFT Reservations

3.1 Effect of a Linden VFT Reservation: A Linden VFT Reservation is a prerequisite to scheduling capacity and/or energy on the Linden VFT Facility. A holder of a

confirmed Linden VFT Reservation may submit offers to schedule capacity and/or energy into the Transmission System at the Point of Interconnection over the Linden VFT Facility.

3.2 Recallability: A Non-Firm Linden VFT Reservation released pursuant to Section 3.7 is recallable by a holder of a Firm Linden VFT Reservation that has retained the right of recall until the deadline posted on the OASIS which shall be based on the time necessary for submittal of energy bids to meet installed capacity obligations in PJM. The procedures and prerequisites for the exercise of recall rights are set forth in Section 4.2.2.

3.3 Term of Service

3.3.1 Firm Linden VFT Reservation: The minimum term of a Firm Linden VFT Reservation shall be one day and the maximum term shall be equal to the term of agreement allocating rights to the Primary Rights Holder, the capability of the Linden VFT Facility pursuant to Section 2.1 of this Schedule. The terms and conditions applicable to Firm Point-To-Point Transmission Service in Part II of the Tariff shall apply to any and all Firm Linden VFT Reservations.

3.3.2 Non-Firm Linden VFT Reservation: The terms and conditions of Non-Firm Point-To-Point Transmission Service in Part II of the Tariff shall apply to any and all Non-Firm Linden VFT Reservations.

3.3.3 Limitations. A Linden VFT Transmission Customer holding a Firm Linden VFT Reservation or Non-Firm Linden VFT Reservation may not submit a request for scheduling of capacity and energy over the Linden VFT Facility that exceeds the period or megawatt amount of its Linden VFT Reservation.

3.4 Acquisition of Linden VFT Reservations: Linden VFT Reservations are initially allocated to Primary Rights Holders pursuant to Section 2.1 Third parties may purchase Firm Linden VFT Reservation or Non-Firm Linden VFT Reservations through (i) assignment pursuant to Section 3.5 of this schedule or (ii) voluntary or default release through Transmission Provider's resale procedures as stated in the Tariff and the Regional Scheduling Practices in accordance with Section 3.7 of this Schedule. The holder of a Linden VFT Reservation that sells or assigns its rights is hereafter referred to as the Reseller. The entity purchasing a Linden VFT Reservation through resale is hereafter referred to as the Buyer.

3.5 Assignment of Linden VFT Reservation: The Primary Rights Holder of a VFT Reservation may assign its VFT Reservation to third parties in accordance with the terms of the agreement between the Linden VFT Transmission Owner and the Primary Rights Holder provided that notice of such assignment is provided to the Transmission Provider with such information provided on the OASIS. Subject to Commission approval of any necessary filings, a holder of a VFT Reservation may assign all or a portion of its rights, but only to another Eligible Customer (the Buyer). The compensation to the Reseller shall be at rates established by agreement with the Buyer. Notice of such assignment shall be provided to the Transmission Provider as soon as possible after any assignment occurs but in any event, notification must be

provided prior to any submission of offers to schedule capacity and energy pursuant to such VFT Reservation by the Buyer.

3.6 Limitations on Resale of Linden VFT Reservations: If the Buyer requests a change in the specifications set forth in the original Linden VFT Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change is done before the start of service, does not exceed the rights granted in the Reseller's original Linden VFT Reservation and will not impair the operation and reliability of the Linden VFT Facility, the Transmission Provider's Transmission System or a Transmission Owner's generation, transmission, or distribution systems. The Reseller shall remain liable for the performance of all obligations under the Linden VFT Service Agreement, except as specifically agreed to by the Reseller, the Buyer, and the Transmission Provider through an amendment to the Linden VFT Service Agreement. A holder of a Linden VFT Reservation shall notify the Transmission Provider of the resale of any Linden VFT Reservation including the rate to be charged in accordance with the deadlines posted in NAESB WEQ 001-11.5.1.for On-OASIS re-sales, and NAESB WEQ 001-11.5.2 for Off-OASIS re-sales.

3.7 Release of Linden VFT Reservation: Linden VFT Reservations may be resold as Available Transmission Capacity (ATC) for acquisition as Linden VFT Service by third parties using the OASIS. Such a resale of transmission service is subject to the requirements in the PJM Manuals, NERC and NAESB Standards.

3.7.1 Voluntary Releases: A holder of a VFT Reservation may offer all or any portion of its VFT Reservation for voluntarily release on a first-come, first-served basis. A VFT Reservation that has been posted for voluntary release under this subsection shall be excluded from the default release procedures set forth in subsection 3.7.2.

3.7.2 Default Releases: In the event that any holder of a Linden VFT Reservation fails to either: (i) submit a request to schedule energy up to the full MW value of its Linden VFT Reservation by noon (12:00 p.m.) one business day prior to the Operating Day or (ii) offer its VFT Reservation for voluntarily release pursuant to subsection 3.7.1, then, the difference between the Total Transfer Capability over the VFT Line in each scheduling hour of the Operating Day and the sum of the valid requests for Linden VFT Schedules and MW amount of Linden VFT Reservations voluntarily released on OASIS for such scheduling hour, shall be deemed released by the Linden VFT Transmission Owner (as Reseller) and shall be posted on the OASIS by the Transmission Provider as Non-Firm ATC for acquisition by third parties on a first-come, first-served basis.

3.7.3 Release Rate: The holder of a Linden VFT Reservation seeking to voluntarily release all or any portion of its Linden VFT Reservation shall provide to the Transmission Provider the rate to be posted on OASIS and charged for such releases. The Linden VFT Transmission Owner may provide the Transmission Provider a rate to be posted on OASIS and charged for default releases pursuant to Section 3.7.2. In the event that the Linden VFT Transmission Owner does not separately provide to the Transmission Provider a rate for default releases, such default releases shall be charged

the lowest rate posted on OASIS for voluntary release of Linden VFT Reservations in the applicable hour.

3.7.4 Character of Service Released: Releases of Linden VFT Reservations made pursuant to the default release provisions in subsection 3.7.2 do not include the right of recall under Section 3.2 and shall be hourly Non-Firm Linden VFT Reservations.

3.7.5 Requirements for Acquisition of Linden VFT Reservations through Release or Assignment: An Eligible Customer shall be eligible to acquire and hold a Linden VFT Reservation through an assignment of a Linden VFT Reservation pursuant to Section 3.5 or release of a Linden VFT Reservation over OASIS pursuant to Section 3.7 if such entity meets all of the requirements for a Linden VFT Transmission Customer except for part (iii) of such requirements.

3.7.6 Resale Rate: The Reseller of a Linden VFT Reservation shall post the rate on OASIS and will be credited for completed re-sales of its service. The Reseller of a Linden VFT Transmission Reservation and the resale Buyer shall be credited/charged the rate as agreed and posted on the OASIS for the Linden VFT Reservations resold.

3.8 Billing and Payment for Linden VFT Reservations:

3.8.1 Linden VFT Reservations Allocated to Primary Rights Holders Pursuant to Section 2.1: The billing and payment of rates or charges applicable to the allocation of Firm or Non-Firm Linden VFT Reservations to the Primary Rights Holder pursuant to section 2.1 shall be determined pursuant to arrangements between the Linden VFT Transmission Owner and the Primary Rights Holder and not under this Tariff.

3.8.2 Linden VFT Reservations Acquired Through Resale Pursuant to Section 3.7.1: An entity acquiring a Linden VFT Reservation through a Resale over the OASIS pursuant to subsection 3.7.1 shall be billed the applicable rate which is posted on OASIS pursuant to subsection 3.7.3. The Transmission Provider will credit/bill both parties according to the applicable rate and the transaction shall be settled through Transmission Provider's settlements.

3.8.3 Linden VFT Reservations Acquired Through Default Resale: The Transmission Provider shall bill an entity acquiring a Linden VFT Reservation through a default resale the applicable rate which is posted on OASIS pursuant to subsection 3.7.3. Any revenues received from the acquisition of Linden VFT Reservations subject to default release provisions shall be paid by the Transmission Provider to the VFT Transmission Owner. A Linden VFT Transmission Customer shall pay the applicable rates for the megawatt amount of the Linden VFT Reservation for each hour regardless of whether such holder(s) submitted a schedule for transmission service over the Linden VFT Facility in such hour.

4. Linden VFT Schedules

4.1 Nature of Transmission Service over the Linden VFT Facility: Linden VFT Schedules shall be requested in accordance with NERC and NAESB Standards, including requirements relating to E-Tagging and Transmission Line Relief procedures. An entity seeking to schedule use of the Linden VFT Facility must hold a Linden VFT Reservation for no less than the amount of megawatts of service being requested. Deadlines for scheduling the use of the Linden VFT Facility shall adhere to the Transmission Provider's deadlines for scheduling as provided by the Transmission Provider's manuals and consistent with the deadlines for scheduling Point to Point Transmission Services as described in Part II of the Tariff.

4.2 Submission of Scheduling Requests, Award of Reservations, Curtailment and Interruption of Linden VFT Schedule:

4.2.1 Submission of Scheduling Requests: A Linden VFT Transmission Customer holding a Linden VFT Reservation has the right to submit requests for Firm Linden VFT Schedules or Non-Firm Linden VFT Schedules commensurate to the Linden VFT Reservations held by that entity.

4.2.2 Exercise of Recall Rights: An Eligible Customer holding a Firm Linden VFT Reservation, that retains the right of recall, may exercise such recall rights by providing notice, until the deadline posted on the OASIS which shall be based on the time necessary for submittal of energy bids to meet any installed capacity obligations in PJM, to the Transmission Provider that it wishes to exercise its right of recall. The exercise of a recall right pursuant to notice to the Transmission Provider shall immediately act to recall the Linden VFT Reservation previously released by the Eligible Customer and acquired by a third party under the assignment provisions set forth in Section 3.5 or the release procedures set forth in Section 3.7

4.3 Scheduling of Capacity and Energy over the Linden VFT Facility: The Transmission Provider shall evaluate all requests to schedule capacity and energy for injection into the Transmission System at the Point of Interconnection based on economic merit order. In the event of a tie within economic merit, a scheduling request made pursuant to a Firm Linden VFT Reservation shall have priority over a scheduling request made pursuant to a Non-Firm Linden VFT Reservation. In the case of an economic merit order tie between two or more scheduling requests using a Firm Linden VFT Reservation, the award of the scheduling reservation shall be on a pro rata basis. In the case of an economic merit order tie between two or more scheduling requests based on Non-Firm Linden VFT Reservations, the reservation classification of the Non-Firm Linden VFT Reservation (Monthly, Weekly, Daily or Hourly) shall then be used as the tiebreaker, with the longer term of Non-Firm Linden VFT Reservation receiving priority. In the case of a further tie within the sub-category of Non-Firm Linden VFT Reservations (Monthly, Weekly, Daily or Hourly), the timestamp order of the submission of requests to schedule service over the Linden VFT Facility shall be used as a tie-breaker. A holder of Linden VFT Reservations is limited in its total capacity and energy schedule for its Linden VFT Schedule to the higher of either its Firm or Non-Firm Linden VFT Reservations.

4.4 Limitations on Scheduling Amount: The Linden VFT Facility has a minimum total scheduling requirement. of 1 MW at the Linden VFT Point of Receipt. The Linden VFT

Facility has a maximum continuous scheduling capability of the lower of the Total Transfer Capability ("TTC") set by the Transmission Provider or 330 MW at the Linden VFT Point of Delivery. In the event that the total megawatt of schedules determined by the Transmission Provider is greater than the lower of the TTC or 330 MW at the Linden VFT Point of Delivery, all schedules above the maximum capability shall be rejected.

4.5 Curtailment of Linden VFT Schedules: In the event that a Curtailment or interruption of Linden VFT Schedules is required to maintain reliable operation of the Linden VFT Facility and the systems directly and indirectly interconnected with the Linden VFT Facility, any such Curtailment implemented by the Transmission Provider shall be based upon the priority of the associated Linden VFT Reservations. For Curtailment or interruptions of Linden VFT Schedules based on Firm Linden VFT Reservations will be performed on a pro rata basis. Curtailment of Linden VFT Schedules based on Non-Firm Linden VFT Reservations shall first be based on the Non-Firm Linden VFT Reservation classification (i.e., Monthly, Weekly, Daily, Hourly) with the longer term of Non-Firm Linden VFT Reservation receiving priority. In the case of a tie within the Non-Firm Linden VFT Reservation classifications, the time stamp order of the submission of valid bids/offers to schedule service over the Linden VFT Facility shall be used as a tiebreaker. The Transmission Provider shall provide advance notice of any Curtailment of Linden VFT Schedules to all affected Linden VFT Transmission Customers where such notice can be provided consistent with Good Utility Practice. The Transmission Provider shall curtail Linden VFT Schedules over the Linden VFT Facility as required by NERC Standards and the Joint Emergency Operating Protocol for the Linden VFT Scheduled Line which is posted on the PJM website. The Transmission Provider shall curtail Linden VFT Schedules over the Linden VFT Facility for reliability of the Transmission System pursuant to the separately reserved Transmission Service over the Transmission System pursuant to Part II or Part III of the Tariff to the Linden VFT Facility and the Transmission Provider's Manuals.

4.6 Transmission Service Over the Transmission System. Prior to the commencement of a Linden VFT Schedule under this Schedule 16-A, a Linden VFT Transmission Customer shall arrange such Transmission Service over the Transmission System pursuant to Part II or Part III of the Tariff as may be necessary pursuant to the Tariff for delivery of energy, capacity or ancillary services over the Transmission System from the Point of Delivery of the Linden VFT Facility for at least the same time period as the Linden VFT Schedule provided under this Schedule 16-A. Reserving such Transmission Service from the Linden VFT Facility is a required precondition to acquiring a Linden VFT Schedule. The Linden VFT Transmission Customer is responsible for all charges associated with Transmission Service for delivery of capacity and energy from the Point of Delivery of the Linden VFT Facility.

5. Liability

The Transmission Provider and any holder of a Linden VFT Reservation which releases or resells its Linden VFT Reservation through resale procedures set forth in Section 3.5 and 3.7 of this Schedule 16-A shall be held harmless with regard to any claim which may be raised by any party regarding the award of the released Linden VFT Reservation, except to the extent that such party successfully establishes that the releasing party has incorrectly selected the party

acquiring such released Linden VFT Reservation as the result of gross negligence or willful misconduct. The liability of the Transmission Provider shall be limited by the terms and conditions of Section 10 of the Tariff and the provisions of the Operating Agreement.

6. Losses and Inadvertent Energy

Real power losses and inadvertent energy across the Linden VFT Facility shall be allocated solely to Linden VFT Transmission Customers that schedule Firm or Non-Firm transmission service over the Linden VFT Facility on an hourly pro rata basis, except for hours with no Linden VFT Schedules, in which case any real power losses and inadvertent energy across the Linden VFT Facility shall be allocated to Linden VFT Transmission Customers that schedule Firm or Non-Firm transmission service over the Linden VFT Facility on a monthly pro rata basis.

7. Congestion Costs and FTRs

A Linden VFT Schedule provides a physical right to deliver energy over the Linden VFT Facility. Accordingly, no congestion costs shall be calculated over the Linden VFT Facility and no FTRs or their equivalent shall be offered for a Linden VFT Schedule. This provision is not meant to preclude any allocation of financial transmission rights, auction revenue rights or their equivalent awarded to the Linden VFT Transmission Owner pursuant to Part VI of the Tariff. Such rights would be allocated to Primary Rights Holders in accordance with Section 2.1.

8. Measurement and Posting of ATC and TTC

The ATC and TTC of the Linden VFT Facility shall be calculated and posted on the OASIS by the Transmission Provider consistent with the requirements of the Tariff.

9. Payment of Other Charges Required for a Linden VFT Schedule

The Linden VFT Transmission Customer is responsible for charges applicable to a Linden VFT Schedule provided under this Schedule 16-A, including, but not limited to, any congestion and loss charges, redispatch costs, transitional revenue neutrality charges, scheduling, administrative, hardware or software upgrade charges, control area or administrative services charges or ancillary service charges applicable to the Transmission Provider's administration of transmission service over the Linden VFT Facility (collectively, the "Linden VFT Service Administration Charges"). In the event that any such Linden VFT Service Administration Charges are billed by the Transmission Provider to the Linden VFT Transmission Owner, the Linden VFT Transmission Owner may bill the Linden VFT Transmission Customer for such charge, and the Linden VFT Transmission Customer shall pay the Transmission Provider, on behalf of the Linden VFT Transmission Owner, such Linden VFT Service Administration Charges pursuant to this Section 9 as a condition of receiving transmission service over the Linden VFT Facility.

In the event that any other charges related to the construction, maintenance, operation or upgrading of the Transmission System are assessed by the Transmission Provider to the Linden

VFT Transmission Owner for the use of the Linden VFT Facility for injection of energy or capacity into the Transmission System, the Linden VFT Transmission Owner may bill the Primary Rights Holder, and the Primary Rights Holder shall pay the Transmission Provider, on behalf of the Linden VFT Transmission Owner, such charges pursuant to this Section 9 as a condition of receiving transmission service over the Linden VFT Facility. The issuance and time for payment of charges under this Schedule 16-A shall be consistent with the billing and payment provisions of Section 7 of the Tariff.

Any failure of a Linden VFT Transmission Customer or a Primary Rights Holder to pay any of the charges referenced in this Section 9 shall be deemed a failure to pay by the Linden VFT Transmission Owner.

EXHIBIT A TO SCHEDULE 16-A

Form of Service Agreement for
Transmission Service for Imports over the Linden VFT Facility

1.0 This Service Agreement, dated as of _____, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the "Transmission Provider") and _____ ("Linden VFT Transmission Customer").

2.0 The Linden VFT Transmission Customer has been determined by the Transmission Provider to have a Completed Application for a Linden VFT Reservation under the Tariff.

3.0 If required, the Linden VFT Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) 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.

5.0 The Transmission Provider agrees to provide and the Linden VFT Transmission Customer agrees to take and pay for the Linden VFT Reservation in accordance with the provisions of Schedule 16-A of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representatives as indicated below.

Transmission Provider PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, PA 19403-2497
Linden VFT Transmission Customer _____ _____ _____

7.0 The Tariff, including Schedule 16-A, 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:	_____	_____	_____
	Name	Title	Date

Linden VFT Transmission Customer:

By:	_____	_____	_____
	Name	Title	Date

CERTIFICATION

I, _____, certify that I am a duly authorized officer of _____ (Linden VFT Transmission Customer) and that _____ (Linden VFT 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.

_____
(Name)

_____
(Title)

Subscribed and sworn before me this _____ day of _____, _____.

_____
(Notary Public)

My Commission expires: _____

Specifications For Transmission Service for Imports Over Linden VFT Facility

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted.
_____

3.0 Point of Receipt: NYISO (at the Linden Cogen 345 kV ring bus in Linden, New Jersey)

Delivering Party: _____

4.0 Point of Delivery: VFT Switching Station in Linden, New Jersey

Receiving Party: _____

5.0 Maximum amount of energy to be transmitted (Reserved Transmission Capability):
_____

6.0 Designation of party(ies) subject to reciprocal service obligation:
_____
_____
_____

8.0 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 and Schedule16-A).

8.1 Linden VFT Reservation Charge:
_____
_____

8.2 Linden VFT Service Administration Charges:

_____
_____

8.3 Linden VFT Transmission Enhancement Charges:

_____

ATTACHMENT A-1

Form Of Service Agreement For
The Resale, Reassignment Or Transfer Of
Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between _____ (the Transmission Provider) as the administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and _____ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

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:

_____

_____

_____

Counterparty:

_____

_____

_____

Assignee:

_____

_____

_____

6.0 The Tariff 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.

Transmission Provider:

By:_____ _____ _____
Name Title Date

Counterparty:

By:_____ _____ _____
Name Title Date

Assignee:

By:_____ _____ _____
Name Title Date

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt:_____

Delivering Party:_____

4.0 Point(s) of Delivery:_____

Receiving Party:_____

5.0 Maximum amount of reassigned capacity: _____

6.0 Designation of party(ies) subject to reciprocal service obligation: _____
_____
_____
_____

7.0 Name(s) of any Intervening Systems providing transmission service: _____
_____

8.0 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.)

8.1 Transmission Charge: _____
_____

8.2 System Impact and/or Facilities Study Charge(s):
_____
_____

8.3 Direct Assignment Facilities Charge:_____
_____

8.4 Ancillary Services Charges: _____
_____
_____
_____
_____
_____
_____

9.0 Name of Reseller of the reassigned transmission capacity:
_____

ATTACHMENT C

Methodology To Assess Available Transfer Capability

The Transmission Provider will be solely responsible for determinations of Available Transfer Capability (ATC). The Transmission Provider will post firm and non-firm ATC projections on the OASIS for interfaces between neighboring Balancing Authorities and the PJM Region, and other path locations of significant commercial interest will be added as appropriate.

ATC of a particular path is an approximate indication of the anticipated transmission transfer capability remaining on the transmission network that could be scheduled for further commercial activity relative to the designated path under the conditions studied. Specific study of conditions, including source and sink of generation and load, is required before firm transmission service commitments can be made.

Transfer capability of the transmission network is limited by physical and electrical characteristics of the system including thermal equipment loading, voltage, and stability considerations and provisions of coordination agreements. Transfer capability is evaluated based on base system loading and an assessment of critical contingencies on the transmission system. The critical contingencies will be defined as appropriate. The Transmission Provider's calculation of transfer capability will be consistent with the principles in the NERC standards. These calculations will be performed through a combination of planning and operational analyses, employing both Energy Management System real-time functionality and off-line analytical tools as appropriate. Firm and non-firm ATC will be determined consistent with NERC standards, taking into account the Transmission Reliability Margin (TRM), Existing Transmission Commitments (ETC) and Capacity Benefit Margin (CBM) (see below) in order to preserve the emergency capability of the PJM Region to serve load serving entities. Firm ATC on any path will be limited to assure that emergency import capability will be available to Network Customers when needed through the reservation of capacity benefit margin, equivalent to a firm point-to-point transmission service reservation for delivery from systems outside of the PJM Region to serve the load serving entities within such region.

Determination of ATC requires that base system conditions be identified and modeled for the period being analyzed. These conditions include projected demand, anticipated generation availability, anticipated transmission system facility availability, expected energy transactions, and information about neighboring regions that affect the transfer capability of the PJM Region. For hourly through monthly calculations, these conditions are based on the Transmission Provider's operational assessments of load trends, unit commitment profiles, maintenance schedules and ETC. Long-term calculations are based on planning loads, expected maintenance schedules, typical generation patterns, and ETC.

Any dispute regarding a determination of ATC by the Transmission Provider, or regarding the data used by the Transmission Provider in such a determination, shall be resolved pursuant to the dispute resolution procedures of Section 12 of this tariff.

ATC and AFC Calculations Using Flowgate Methodology

The Available Flowgate Capability (AFC) calculation methodology used by the Transmission Provider is the Flowgate Methodology as described in the Available Transfer Capability Implementation Document (ATCID). The ATCID is included on the PJM OASIS page under ATC information . The Flowgate Methodology uses analytical tools to examine critical flowgates over the PJM Region and adjacent regions (per seams agreements) and converts AFC values into particular path ATC values, which are posted on the PJM OASIS. For Firm and Non-firm Transmission Service ATC calculations the Transmission Provider shall account for Postbacks of redirected services, unscheduled service, and counterflows. PJM critical flowgates may include, but are not limited to thermal flowgates, voltage/stability flowgates, coordinated flowgates, and reciprocal coordinated flowgates.

Overview and Process Flow Diagram

The process for the Transmission Provider's AFC/ATC calculation is illustrated in the Exhibit 1 flow diagram. The text that follows describes the inputs, outputs and processes performed within each of the sub-processes contained in Exhibit 1. The Transmission Provider calculates Firm and Non-firm Transmission Service ATC for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule), and planning horizon (beyond the operating horizon).

AFC/ATC Process Flow Diagram

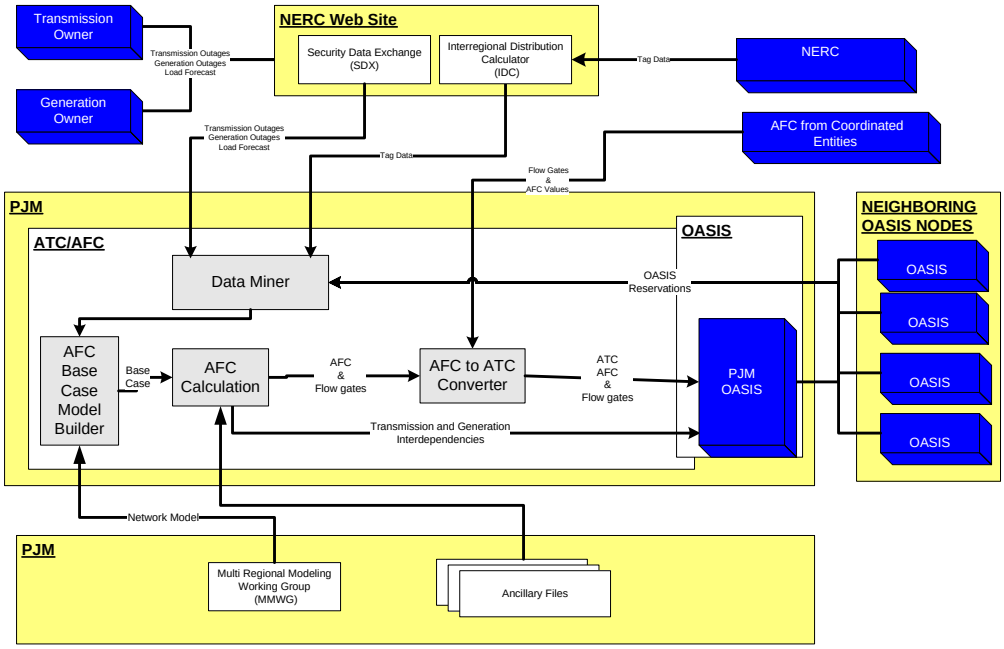


Exhibit 1

AFC Flowgate Methodology

Determining AFC and ATC using the Flowgate Methodology is a multi-step integrated process which is described in detail in the ATCID. PJM uses the following mathematical algorithms to calculate AFC and ATC. The actual detailed AFC and ATC algorithms are available on the PJM OASIS website at the following link:

ftp://ftp.pjm.com/oasis/afc-atc-algorithms.pdf

AFC = flowgate rating – ETC – TRM – CBM + Postbacks + counterflows.

The AFC Calculation is the amount of unused transfer capability on a flowgate after accounting for base case conditions represented by solved base case flows and applying the impacts of non-base case commitments and flowgate specific margins.

$$ATC = \text{Minimum}\{AFC_1 / \text{Transfer Response Factor}, \ldots, AFC_n / \text{Transfer Response Factor}\}$$

The AFC to ATC converter translates the flowgate AFC values into path ATC values for posting to the OASIS. The ATC calculation is the minimum AFC of a set of limiting flowgates divided by the transfer response factor or distribution factor on the respective flowgate for a specific Point of Receipt/Point of Delivery pair. The Available Share of Total Flowgate Capability (ASTFC) as prescribed by a congestion management process agreement (e.g., the CMP included in the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM) may be less than the calculated AFC. The posted AFC is set by the ASTFC or the calculated AFC, whichever is most limiting.

An overview of the major components of this process is described below:

- The AFC to ATC converter process utilizes the coordination entity calculated AFC values for non-PJM flowgates. AFC values for coordination entity flowgates calculated by the coordination entity overwrite values that the Transmission Provider's process determines for these Flowgates.

- The Transmission Provider supplies coordination entities with similar values for PJM Flowgates for inclusion in the coordination entity's AFC process.

- Values provided to the OASIS from the AFC/ATC process are continually updated on the OASIS to reflect the reservations or schedules that were accepted or confirmed since the last complete calculation cycle.

Data Miner

Transmission Provider, through data miner process, gathers data from the Transmission Provider and external sources to use as inputs to the AFC/ATC process. These external sources are included in the Transmission Provider's ATCID.

Model Builder

The Transmission Provider develops and maintains seasonal models for the next 18 months. These seasonal models will be developed from the NERC MMWG case library modified for any known model updates. The Transmission Provider's AFC/ATC calculations are based on these seasonal models. The model builder portion of the AFC/ATC engine modifies these seasonal base cases to reflect anticipated conditions such as forecasted load levels, outages, generation dispatch files, and base case transfers (reservations and/or schedules as appropriate) for the AFC/ATC time horizon. The base case models are refined to reflect transmission outages and generation unavailability as provided by the NERC SDX data. Load levels are appropriately adjusted to reflect the modeled conditions using the NERC SDX data. Relevant balancing authorities external to the PJM footprint will be modeled at the appropriate load level with the generation scaled to match loads.

The Transmission Provider develops monthly, weekly, daily, and hourly AFC cases. These cases serve as the base case models for the AFC calculation for a specific period. Solved base

case models for monthly, weekly, daily, and hourly time frames are developed multiple times each day consistent with NERC standards.

The Transmission Provider models some flowgates without contingencies and some with contingencies.

The flowgates modeled without contingencies are the Power Transfer Distribution Factor (PTDF) flowgates, which are flowgates where a single facility or multiple transmission facilities are monitored for a limiting condition. The limiting condition can be due to thermal loading above 100% of the normal rating or due to a thermal rating above 100% of the surrogate rating representing an equivalent voltage or stability limit.

The flowgates modeled with contingencies are the Outage Transfer Distribution Factor (OTDF) flowgates, which are flowgates where a single facility or multiple transmission facilities are monitored for a limiting condition after a contingency event has been simulated to have occurred (one or multiple facilities for the loss of another facility or facilities). The limiting condition monitored can be due to thermal loading above 100% of the 4 hour emergency rating.

For flowgates owned by other parties, Transmission Provider uses the limit provided by that party, subject to the terms of the AFC Coordination and Congestion Management Process sections of the applicable agreements between Transmission Provider and the other parties.

AFC Calculation

The Transmission Provider's AFC/ATC calculation implements the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the Transmission Provider shall account only for firm commitments; (2) for non-firm ATC calculations, the Transmission Provider shall account for both firm and non-firm commitments. Reservations from the PJM and non-PJM OASIS sites are utilized. Flow based analysis will be used to determine and update flowgate loadings for reservations not modeled in the base case and to determine response factors on each flowgate. Flowgate loadings and response factors will be used to determine the individual path ATC values.

- The Transmission Provider recognizes physical network limitations (i.e., flowgates) on PJM and appropriate non-PJM systems in the determination of the path ATC values.

- AFC values received from coordination entites are calculated by those entities according to their AFC methodology.

AFC to ATC Conversion

To calculate ATC, which represents a transfer capability in MW available for sale between a specific Point of Delivery and Point of Receipt, the Transmission Provider will first calculate an AFC for each flowgate. An AFC is defined as follows:

- The available capability in MW on a flowgate, determined by the transmission provider, that is available for further commercial activity. The available capability determined will be dependent on the generation, loads and transmission configuration assumed for the time period studied.

- The AFC accounts for thermal, voltage and stability limits under both pre and post contingency conditions, along with any existing transmission commitments, TRM and CBM.

- The AFC is used to determine the amount of MWs that can be transferred between a specific set of source and sink points. An AFC is skipped using on-the-path logic if the flowgate owner is either the Point of Receipt or Point of Delivery on the path being calculated. The non-firm ATC calculation for the willing-to-pay congestion product on the OASIS includes only external flowgates.

- Counterflow and Postbacks are considered in the calculation of AFC.

Coordination with Neighboring Systems

The Transmission Provider exchanges data with neighboring systems. The Transmission Provider provides transmission reservations, AFC values for Transmission Provider flowgates, and other data. This coordination results in comparable inputs to the AFC calculations. The Transmission Provider utilizes similar information provided by coordinating entities.

Treatment of Existing Transmission Commitments

ETC is committed use of the transmission system, including: (1) Transmission Provider's reservations in accepted or confirmed status; (2) native load commitments; Network Integration Transmission Service; (3) grandfathered transmission rights; (4) Firm Point-To-Point Transmission Service reservations; and if required (5) rollover rights associated with long-term firm service (Point-To-Point Transmission Service and Network Integration Service or grandfathered transmission rights). Existing commitments modeled in the load flow base cases determine the initial flows on the facilities. To the extent there are existing transactions that qualify for rollover rights, they are incorporated in the committed usage.

PJM OASIS reservations that are withdrawn, retracted (not confirmed) or annulled are removed from the ETC and any resulting changes to ATC are incorporated in the next OASIS posting of ATC calculated values. The Transmission Provider's firm and non-firm ATC calculations also account for permanently redirected services, unscheduled service, and counterflows. In the scheduling and operating horizons, reservation impacts are substituted with scheduled impacts. That is, the reservation impact component of ETC is set to zero and the schedule impacts component of ATC is used. In the planning horizon, reservation impacts are used because requests to schedule are often not received in this horizon. That is, the reservation impact component of ETC is set based on Transmission Service Requests for which Transmission Provider has committed to provide service and the schedule impacts component of ATC is set to zero. Additional information is included on this subject in the Transmission Provider's ATCID.

External Flowgates

Flowgates are used in the AFC and ATC calculations. PJM adds or eliminates external flowgates based on the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C. ("Midwest ISO JOA", Article V (FERC Electric Tariff, First Revised Rate Schedule No. 38, *see*, Section 4.2 – Cost of Data and Information Exchange up to and including Section 5.1.12 – Coordination of Transmission Reliability Margin Values); Joint Operating Agreement Among And Between PJM Interconnection, L.L.C., And Progress Energy Carolinas ("PEC JOA"), Article Five (FERC Electric Tariff, First Revised Rate Schedule No. 50, *see*, Article 9 – Coordinated Transmission Planning Studies up to and including Article 12 – Managing Parallels Flow on the VACAR/PJM Interface); and Joint Reliability Coordination Agreement Among And Between Midwest Independent Transmission System Operator, Inc., PJM Interconnection, L.L.C., And Tennessee Valley Authority ("JRCA"), Article Five (the JRCA is not a filed FERC rate schedule; however, Article Five of the JRCA is identical to Article V of the Midwest ISO JOA and Article Five of the PEC JOA). PJM adds or eliminates internal flowgates, at least annually, based on a review of historic operating constraints including flowgates that have been in Transmission Loading Relief (TLR) and other operating conditions as deemed appropriate.

Internal Flowgates

Transmission Provider determines base case flows using the AFC engine. Transmission Provider runs the AFC engine hourly (except in the case of a technical error, system error or planned system outage). The base run includes native and network load (from the load forecast), transmission service that is expected to be scheduled (grandfathered, point-to-point and imports from designated Network Resources), outages and load forecast. Base case flow inputs are updated at least once per day. In the scheduling and operating horizons, Transmission Provider updates scheduled transmission service for each run of the AFC engine. Transmission Provider models all grandfathered agreements and other non-Tariff use of the transmission system as firm service or load. Transmission Provider does not segregate non-Tariff service in the AFC calculation.

On an annual basis (or sooner if required by NERC MOD Standards), PJM shall review internal flowgates using the following methodology:

a. The Transmission Provider shall include all flowgates in its footprint that have initiated a TLR event in the 12 months prior to the annual review.

b. The Transmission Provider shall include applicable System Operating Limit (SOL) and Interconnection Reliability Operating Limits (IROL) flowgates per NERC TOP-002 R-12 standards (or successor). Any facility that PJM monitors that is not considered an IROL facility is consider a SOL. Applicable SOL and IROL flowgates shall include at a minimum those flowgates identified in the TRM process described in this Attachment C AFC process.

c. The Transmission Provider shall add or remove flowgates to its AFC process in accordance with NERC MOD standards.

The Transmission Provider may eliminate flowgates that do not continue to meet the criteria above.

A reservation with rollover rights is reflected in ETC in the amount of transmission service reserved as if the customer has exercised its rollover right. If the deadline for a customer to exercise its rollover right for a given reservation has passed, and the customer did not exercise its rollover right, the amount associated with the unexercised rollover right no longer is included in the amount of reservations.

Treatment of Capacity Benefit Margin

Explanation of CBM

Transmission Provider uses the NERC approved definition of CBM, which is the amount of firm transmission transfer capability preserved by Transmission Provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by an LSE only in times of emergency generation deficiencies. Additional information is included in the Transmission Provider's Capacity Benefit Margin Implementation Document (CBMID) posted on the PJM OASIS page under ATC Information.

The CBM is a reliability margin applied to the flowgate in the AFC Calculation. CBM is only applied to firm ATC calculations where the PJM Region is the delivery point. The Transmission Provider consistently applies CBM in planning and operations and does not double count for this reliability margin (i.e., this margin is not included in TRM). For non-PJM flowgates, the Transmission Provider uses the CBM values provided by coordination entities for the AFC calculation on these flowgates.

Through the sharing of installed generating capacity via transmission interconnections, systems have relied on transmission import capability to reduce their required installed generating capacity necessary to provide reliable service to Network Customers. In order to ensure that PJM has the ability to import external generation for the purpose of serving Network Customers, a portion of the transfer capability will be set aside. CBM is set aside on paths based on the expected delivery of energy from entities with which the Transmission Provider has emergency energy agreements at the time of the Transmission Provider's forecast peak load. This capability, known as the Capacity Benefit Margin, is a reflection of the mutual benefit of interconnected operations and reservation of this margin allows a system to reduce its installed generating capacity below that which may have otherwise been required if transmission interconnections did not exist.

The CBM is determined through the auspicious of the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (PJM Rate Schedule FERC No. 44) (RAA). Capitalized terms in this section that are not defined in this section or section 1 of the Tariff are defined in the RAA.

CBM is determined through the Transmission Planning Evaluation of Import Capability. This evaluation establishes the amount of emergency power that can be reliably transferred to the PJM Region from adjacent regions in the event of a PJM Region generation capacity deficiency. To determine the import transfer limit, several emergency scenarios are replicated and the limit represents a normalization of expected values. This transfer limit determines the PJM Region tie benefit that is subsequently used in calculating the PJM Region reserve requirement. An annual recalculation of the PJM Region import capability is not required, since the import capability far exceeds the CBM value specified in Schedule 4 of the RAA.

CBM is a key input into the annual resource adequacy study performed by Transmission Provider. The purpose of this study is to determine the PJM Region Installed Reserve Margin (IRM) required by the PJM Region to satisfy a one day in 10 year Loss of Load Expectation (LOLE). Transmission Provider uses a probabilistic methodology to perform the resource adequacy study. The study assumptions and results are subject to stakeholder review and comment. The resulting IRM is expressed as a percentage of the forecasted annual peak load.

The CBM assessment in the PJM Region is a unique method that is regionally specific because interface capability greatly exceeds CBM and because Transmission Provider centrally secures capacity for the PJM Region capacity market.

Transmission Provider's annual resource adequacy study is based on the probabilistic methods and criteria described in Schedule 11 of the RAA, the Operating Agreement and in the PJM Manuals. The resource adequacy study considers the following data and forecasts as necessary:

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

2. Forecasts of aggregate seasonal load shape of the parties bound by the RAA which are consistent with forecast averages of 52 weekly peak loads prepared by Transmission Provider.

3. Variability of loads within each week, due to weather, economic forecast uncertainty, and other recurring and random factors, as determined by Transmission Provider.

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

5. Generator Forced Outage rates for existing mature generating units based on data submitted by generation owners, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

6. Generator Maintenance Outage factors and planned outage requirements based on forecasts and historical data submitted by the generation owners.

7. Miscellaneous adjustments to capacity due to all causes, as determined by the Office of the Interconnection, based on forecasts submitted by the generation owners.

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

The value of the capacity benefit margin as filed as part of the RAA periodically is reviewed by Transmission Provider, in consultation with the Members Committee, and can be modified, if necessary, to balance external emergency capacity assistance and internal installed capacity reserves so as to minimize the total cost of the capacity reserves of the RAA participants, consistent with the Reliability Principles and Standards.

Use of CBM in an Emergency

The procedures for the use of CBM in an emergency, are described in Section 2 of PJM Manual 13: Emergency Operations and are consistent with NERC and ReliabilityFirst Corporation's Energy Emergency Alert defined in NERC's EOP-002 standards. Transmission Provider is responsible for declaring the existence of an emergency, and for directing the operations of the PJM Members as necessary to manage, alleviate, or end a capacity shortage. Transmission Provider uses CBM in an emergency only on behalf of LSEs. LSEs only use CBM through the Transmission Provider's use of CBM on the LSEs behalf.

Emergency use of CBM will be considered use of Network Integration Transmission Service and there will be no additional charge for such use. Because an area is in an EEA 2 and Transmission Provider is taking steps to avoid shedding firm load, the use of CBM will have a NERC curtailment priority of 7 and will only be curtailed with other firm uses on a proportional basis.

Transmission Provider utilizes CBM on behalf of LSEs as described below.

- Transmission Provider reviews the level of dependency on external transactions to serve the load in the PJM Region. Transmission Provider shall log occurrences where CBM is implemented. Transmission Provider shall notify external systems via the Reliability Coordinator Information System (defined in NERC EOP-002) or successor, a communications tool located at the NERC website to post potential or actual alert information, and Transmission Provider Members via the Transmission Provider's website and issue appropriate NERC alert levels consistent with NERC EOP- 002.

- CBM shall be used only after the following steps have been taken: all non-firm sales have been terminated, direct-control load management has been implemented, and customer interruptible demands have been interrupted. Due to the nature of emergencies, Transmission Provider may skip or reorder the steps in accordance with Good Utility Practice. CBM may be used to reestablish Operating Reserves.

- CBM shall only be used if the PJM Region is experiencing a generation deficiency to increase generation in the PJM Region. Transmission Provider shall use CBM, on behalf

of an LSE, in order to exercise emergency energy agreements and to implement approved emergency energy bids. Transmission Provider does not displace Non-Firm Point-To-Point Transmission Service and/or secondary service, described in section 28.4 of the Tariff, imports until the Transmission System is constrained. If the Transmission System is constrained, CBM is used by Transmission Provider to displace such imports to provide more reliable service to load during capacity deficiencies.

- Unused CBM is included in the AFC/ATC calculations as Non-Firm Point-To-Point Transmission Service and/or secondary service, described in section 28.4.

Transmission Planning Evaluation of Import Capability

The Transmission Provider conducted an Expected Import Capability Study (EICS) to evaluate the emergency import limits of the Transmission Provider under summer peak conditions. That study showed the Transmission Provider's import capability limit. This limit is evaluated annually to assess whether the CBM value should be changed. This evaluation is discussed in the annual PJM Reserve Requirement Study (RRS). While the Transmission Provider can import more than the CBM value issued in the study, the additional import capability is reflected in ATC through the OASIS postings. This allows the additional import capability to be used in the marketplace. The reliability benefit of CBM saturates near the limit issued in the RRS.

Treatment of Transmission Reliability Margin (TRM)

The Transmission Reliability Margin (TRM) is a reliability margin applied to the flowgate in the AFC Calculation. TRM accounts for the inherent uncertainty in system conditions and its associated effects on ATC calculations and the need for operating flexibility to ensure reliable system operation as system conditions change. The Transmission Provider, following the NERC MOD-008-1, or successor Reliability Standard, calculates TRM for flowgates and may include uncertainty items using a process described in the Transmission Reliability Margin Implementation Document (TRMID). The flowgates are identified following NERC MOD-030-2, or successor Reliability Standard, through processes described in the ATCID. Both the TRMID and ATCID are posted PJM OASIS page under ATC Information.

Transmission Provider calculates TRM using the following methodology:

1. TRM shall be set using components of uncertainty identified in the TRMID for all PJM flowgates except as noted below.

2. TLR and IROL. TRM shall be considered using components of uncertainty identified in the TRMID for all flowgates that had TLR issued in the 12 months prior to Transmission Provider's annual TRM re-evaluation and are Interconnection Reliability Operating Limits (IROLs) located in PJM Manual 37: Reliability Coordination.

3. Constrained Operations. TRM may be set using components of uncertainty identified in the TRMID for flowgates that were bound constrained in the 12 months prior to Transmission Provider's annual TRM re-evaluation.

4. Current and Expected Operating Conditions. During times of unusual circulation or other operating conditions, Transmission Provider may set a larger TRM than indicated in sections 1, 2, and 3.

5. Historic Conditions. Notwithstanding sections 1, 2, and 3 above, Transmission Provider may set TRM on specific flowgates consistent with components of uncertainty identified in the TRMID and NERC MOD-008-1, or successor Reliability Standard.

6. For non-PJM flowgates, the Transmission Provider uses the TRM values provided by coordination entities for the PJM AFC calculation on these flowgates in accordance with applicable agreement with such entities.

Transmission Provider uses data from Transmission Provider's Energy Management System (EMS) historic database, IROL and NERC's Interchange Distribution Calculator (IDC) in the calculation of TRM.

Transmission Provider uses TRM in all AFC calculations. Transmission Provider includes TRM in the AFC/ATC calculation to provide a reasonable level of assurance that the interconnected transmission network will be secure. TRM is not scheduled against or explicitly used for the delivery of energy. It is preserved as a reliability margin to reflect the uncertainty of the operation of the electric system (i.e., to prevent oversubscription of the transmission system). Transmission Provider flowgates with their TRM, CBM, and ratings are posted on the PJM OASIS paged under ATC Informatiion at:

ftp://ftp.pjm.com/oasis/fgates-definitions-posting.csv

Total Transfer Capability (TTC)

The Total Transfer Capability (TTC) is the amount of transfers that can be reliably delivered across the interconnected transmission system for the forecasted conditions. The Transmission Provider uses the network AFC methodology to calculate ATC, which does not use TTC as an input. The flowgate rating is an equivalent starting point in the AFC calculation. However, a TTC value is derived as an output and is posted.

ATTACHMENT F-1

Form of Umbrella Service Agreement for Network Integration Transmission Service Under State Required Retail Access Programs

1.0 This Service Agreement dated as of _____, including the Specifications For Network Integration Transmission Service Under State Required Retail Access Programs attached hereto and incorporated herein, is entered into, by and between PJM Interconnection, L.L.C. ("Transmission Provider") as administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and _____, a transmission customer participating in a state required retail access program and/or a program providing for the contractual provision of default service or provider of last resort service ("Network Customer").

2.0 The Network Customer has been determined by the Transmission Provider to have a valid request for Network Integration Transmission Service under the Tariff and to have satisfied the conditions for service imposed by the Tariff to the extent necessary to obtain service with respect to its participation in a state required retail access program.

3.0 Service under this Service Agreement shall commence on _____, and shall terminate on such date as mutually agreed upon by the parties, unless state law or regulations specify a limited period for service or unless earlier terminated for default under Section 7.3 of the Tariff.

4.0 The Transmission Provider agrees to provide, and the Network Customer agrees to take, Network Integration Transmission Service in accordance with the Tariff, including the Operating Agreement of the PJM Interconnection, L.L.C. ("Operating Agreement") (which is the Network Operating Agreement under the Tariff and 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

Network Customer

_____

_____

_____

IN WITNESS WHEREOF, the Transmission Provider and the Network Customer have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider

By:_____ _____ _____
Name Title Date

Counterparty:

By:_____ _____ _____
Name Title Date

Network Customer

By:_____ _____ _____
Name Title Date

SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE
PURSUANT TO STATE REQUIRED RETAIL ACCESS PROGRAMS

1.0 Term of Service: The term of service under this Service Agreement shall be from _____ until terminated by mutual agreement of the parties, unless state law or regulations specify a limited period for service or unless earlier terminated for default under Section 7.3 of the Tariff.

2.0 Network Operating Agreement: In accordance with Section 29.1 of the Tariff, the Network Customer must be a member of PJM Interconnection, L.L.C. and a signatory to the Operating Agreement.

3.0 Network Load and Network Resources: The Network Customer shall be responsible for the Transmission Provider receiving the information pertaining to Network Load, Network Resources, and Behind The Meter Generation described in this section. Such information shall be provided in accordance with procedures established by the Transmission Provider. With respect to service requests under this umbrella Service Agreement, the Transmission Provider will deem the provision of the information specified in this section as complying with the application requirements set forth in Section 29.2 of the Tariff.

3.1 Network Load: For Network Load within the PJM Region, the Network Customer shall arrange for each electric distribution company ("EDC") delivering to the Network Customer's load to provide directly to the Transmission Provider, on a daily basis, the Network Customer's peak load (net of operating Behind The Meter Generation, but not to be less than zero, unless such generation is separately metered and reported to PJM), by bus, coincident with the annual peak load of the Zone as determined under Section 34.1 of the Tariff. The peak load shall be expressed in terms of tenths of a megawatt and shall include all losses within the PJM Region, including other transmission losses, and distribution losses. Unless a more specific bus distribution is available, the EDC may provide a bus distribution for the Network Customer's peak load proportional to the bus distribution for all of the load in the Zone. The information must be submitted directly to the Transmission Provider by the EDC, unless the Transmission Provider approves in advance another arrangement. For Non-Zone Network Load, the Network Customer shall provide to the Transmission Provider, on a daily basis, the Network Customer's peak load, by interconnection at the border of the PJM Region, coincident with the annual peak load of such area as determined under Section 34.1 of the Tariff. The peak load for such Non-Zone Network Load shall be expressed in terms of tenths of a megawatt and shall not include losses within the PJM Region. Unless a more specific bus distribution is identified and node definition requested, a service request shall be granted upon submission of the information set forth in this Section 3.1 without any further confirmation procedures. If a Network Customer under this Service Agreement, prior to the commencement of service or at any time after the commencement of

service, identifies a more specific bus distribution and requests a node definition for all or part of its Network Load that is served under state required retail access programs, the Network Customer shall notify both the Transmission Provider and the electric distribution company pursuant to the notification procedure and schedule set forth in the PJM manuals. The Transmission Provider, exercising its independent judgment and expertise, shall have the authority to resolve any difference of opinion that may arise between the Network Customer and the electic distribution company as to the applicable bus distribution or node definition. If confirmed, the more specific bus distribution will not be used for billing and settlement purposes, however, until the notification procedure set forth in the PJM manuals is completed, and in no event until June 1, to correspond with the commencement of the annual planning period.

3.2 Network Resources: The Network Customer, as necessary, shall designate from time to time its Network Resources. In the event the Network Resource to be designated is Behind The Meter Generation, the designation must be made before the commencement of a Planning Period as that term is defined in the Operating Agreement and will remain in effect for the entire Planning Period. Such Network Resources must be acceptable to the Transmission Provider as Network Resources in accordance with the Tariff and the Operating Agreement. Designations of resources that have not previously been accepted as Network Resources of any Network Customer or Transmission Customer shall include the information set forth in Section 29.2(v) of the Tariff. Changes in the designation of Network Resources will be treated as an application for modification of service. The Network Customer shall confirm the acceptance of a Network Resource within 15 days of the completion of a System Impact Study or 30 days after completion of a Facilities Study, as is applicable. The Transmission Provider will maintain a current list of Network Resources, which shall be updated from time to time.

3.3 Hourly Load: The Network Customer and/or the EDCs delivering to the Network Customer's load shall provide to the Transmission Provider, on a daily basis, hourly loads and an associated bus distribution for the Network Load. For Network Load within the PJM Region, hourly loads required under this Section shall include all losses within such area, including transmission losses, and distribution losses. The Network Customer shall notify the Transmission Provider whether the Network Customer or the EDC will submit the hourly loads. The submitted load values will include losses and shall be reduced using the applicable loss factor determined by the Transmission Provider whenever a billing determination is calculated under the Tariff without losses.

3.4 Energy Schedules: The Network Customer shall schedule energy for its hourly loads in accordance with the Appendix to Attachment K of the Tariff.

3.5 Interruptible Loads: The Network Customer shall inform or shall arrange for each EDC delivering to Network Customer's load to inform Transmission Provider about the amount and location of any interruptible loads included in the Network

Load. This information shall include the summer and winter peak load for each interruptible load (had such load not been interruptible), that portion of each interruptible load subject to interruption, the conditions under which an interruption can be implemented, and any limitations on the duration and frequency of interruptions.

3.6 Procedures for Load Determination: The procedures by which an EDC will determine the peak and hourly loads reported to the Transmission Provider under Sections 3.1 and 3.3 may be set forth in a separate schedule to the Tariff for each EDC.

3.7 Behind The Meter Generation: For Behind The Meter Generation of a Network Customer that requires metering pursuant to section 14.5 of the Operating Agreement, the Network Customer shall arrange for the Transmission Owner or EDC to provide directly to Transmission Provider information pertaining to such Behind The Meter Generation and the total load at its location as necessary for PJM's planning purposes.

4.0 Energy Imbalance Service: The Network Customer will receive Energy Imbalance Service from the Transmission Provider in accordance with Schedule 4 of the Tariff. Energy Imbalance Service is considered to be PJM Interchange and will be charged at the hourly locational marginal price determined pursuant to Section 2 of the Appendix to Attachment K of the Tariff.

5.0 Reconciliation Billing: For Network Load within the PJM Region, to the extent required, the Transmission Provider will reconcile the Network Customer's hourly energy responsibilities as initially reported to Transmission Provider and its hourly energy consumption based on, or estimated from, metered usage, and provide corresponding charges and credits to Network Customer. Such reconciliation, if required, shall be made at the same rates as Energy Imbalance Service.

6.0 Designation of party subject to reciprocal service obligation: The Network Customer shall comply with Section 6 of the Tariff.

7.0 Name(s) of any Intervening Systems providing transmission service: To the extent any Network Resources are located outside the PJM Region, the list of Network Resources maintained by the Transmission Provider referenced in Section 3.2 of these specifications, shall identify any intervening systems needed to deliver those Network Resources to the Network Customer's retail load.

8.0 Charges: Service under this Service 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.)

8.1 Embedded Cost Transmission Charge: The embedded cost transmission charge shall be determined in accordance with the formula set forth in Section 34 of the Tariff.

8.2 System Impact and Facilities Study Charges: To the extent Network Resources are located outside, or a new resource is added to, the PJM Region, a System Impact Study and/or Facilities Study Agreement and related charges may be required pursuant to Section 32 of the Tariff.

8.3 Direct Assignment Facilities Charge: To the extent that facilities or portions of facilities must be constructed by a Transmission Owner for the sole use or benefit of the Network Customer to accommodate the service requested by the Network Customer, the Network Customer shall be responsible for the cost of such Direct Assignment Facilities, and the charges for such facilities shall be specified at the time that the Transmission Provider determines the facilities that are needed to provide the requested service.

8.4 Ancillary Services Charge: In addition to Energy Imbalance Service, Transmission Provider shall bill the Network Customer for ancillary services in accordance with Schedules 1, 1-A, 2, 3, 5, 6, and 9 of the Tariff. To the extent required, the ancillary services charges shall also be reconciled based on any differences between the Network Customer's hourly energy responsibilities as initially reported to Transmission Provider and its hourly energy consumption based on, or estimated from, metered usage.

8.5 Other Supporting Facilities Charge: None.

8.6 **[Reserved]**

8.7 Other Charges: Transmission Provider shall charge Network Customer any and all other charges set forth in the Tariff applicable to providing Network Integration Service.

9.0 Designated Agent: To the extent that a Designated Agent for one or more Network Customers provides to the Transmission Provider any of the information required by these Specifications, it shall provide the information separately for each Network Customer.

CERTIFICATION

I, _____, certify that I am a duly authorized officer of

_____ (Network Customer) and that

_____ (Network 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.

_____
(Name)

_____
(Name)

Subscribed and sworn before me this ____ day of _____, _____.

_____
(Notary Public)

My Commission expires:_____

2. Determination of Credit.

(a) **Overview.** For each hour with respect to which the Transmission Provider receives payments of Transmission Congestion Charges, determined in accordance with section A of this Attachment, Transmission Congestion Credits shall be allocated to the holders of Financial Transmission Rights. As explained in subsection B(1) above, the Financial Transmission Rights are associated with the points on the Transmission System between which the Firm Transmission User to whom the FTR was originally issued has arranged for the firm transmission of electric energy, whether on a network or point-to-point basis. Holders of FTRs receive credits attributable to the difference, if any, between Congestion Prices at the Point or Points of Receipt and the Point or Points of Delivery associated with the Financial Transmission Rights. As explained in Section 5.2.2 of Attachment K - Appendix, each FTR holder shares in Transmission Congestion Credits to the extent it holds Financial Transmission Rights between the Point or Points of Receipt and the Point or Points of Delivery at which congestion is experienced in a particular hour. Distribution of credits in this manner ensures that each FTR holder will not incur energy costs that are greater than the costs of energy from the generation resources associated with the FTR holder's Financial Transmission Rights. Target allocations of Transmission Congestion Credits to holders of Financial Transmission Rights are calculated in accordance with Section 5.2.5 of Attachment K – Appendix and Transmission Congestion Credits are distributed in accordance with that allocation, as described in Sections 5.2.5 and 5.2.6 of Attachment K – Appendix.

(b) **Assignment of Financial Transmission Rights.** Financial Transmission Rights shall be obtained pursuant to Attachment K - Appendix.

(c) **Assignment of Auction Revenue Rights.** Auction Revenue Rights shall be assigned pursuant to Attachment K - Appendix.

(d) **Target Allocation of Credits to Financial Transmission Rights.** Target Allocation of Transmission Congestion Credits for each FTR holder for each hour shall be pursuant to Attachment K – Appendix.

(e) **Distribution of Transmission Congestion Credits.** Distribution of Transmission Congestion Credits shall be pursuant to Attachment K – Appendix.

C. Offset of Transmission Congestion Charges and Transmission Congestion Credits.

The Office of the Interconnection, on behalf of PJMSettlement, shall take into account both (i) amounts payable by a Transmission User with respect to Transmission Congestion Charges as determined in accordance with Section A of this Attachment, and (ii) amounts payable to a Transmission User with respect to Transmission Congestion Credits as determined in accordance with Section B of this Attachment.

1.6A PJMSettlement

1.6A.1 Scope of Services

PJMSettlement shall perform the services pertaining to the PJM Interchange Energy Market specified in this Agreement, including, but not limited to, the following:

(i) PJMSettlement shall be the Counterparty to transactions (including ancillary services transactions) in the PJM Interchange Energy Market administered by the Office of the Interconnection;

(ii) PJMSettlement shall render bills to the Market Participants, receiving payments from and disbursing payments to the Market Participants; and

(iii) For purposes of clarity, PJMSettlement shall not be a Counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

ATTACHMENT M-2 (PSE&G)
PROCEDURES FOR LOAD DETERMINATION

The procedures by which PSE&G will determine the peak and hourly loads reported to the Transmission Provider are set forth in the following provisions.

A. CUSTOMER CAPACITY AND TRANSMISSION OBLIGATIONS

Both the capacity (generation) and transmission obligations for retail and wholesale customers have been developed so that the sum of the individual customer obligations within a zone will total the PJM zonal (LDC's) obligation. This zonal obligation may vary as provided for under the PJM Reliability Agreement due to the effects of net new customer load. PJM uses a "top down" method in allocating the PJM system peak load to each LDC, while the transmission loads are LDC (zone) specific. Each LDC uses a "bottom up" approach to calculate individual peak loads based upon the zonal loads. These preliminary customer peak loads are then scaled up or down to match (1) the normalized peak load calculated by PJM for each LDC for capacity purposes and (2) the actual zonal load for transmission purposes. Capacity peak loads, aggregated by Supplier, are adjusted for reserves and diversity by PJM. Transmission peak loads, aggregated by Supplier, transmitted to PJM need no further adjustment.

Since retail customers within a PJM zone (LDC service area) will be free to change suppliers, an obligation "tag" is needed to be assigned to each customer for both capacity and transmission obligations. These tags will be recalculated periodically to incorporate new customers, changing customer usage and to ensure consistency with the PJM and LDC peak loads and obligation calculations.

Discussed below is an explanation of how each individual customer's capacity and transmission peak load will be determined.

1. Customer Capacity Peak Load Determination

To calculate a retail and wholesale customer's capacity peak load share, the total normalized peak demand is first determined for each zone by PJM. In the case of the PSE&G zone, the normalized peak load in the Summer of 1998 was approximately 9200 MW. This normalized peak load was based upon allocating PJM's normalized peak load to PSE&G using the ratio between PSE&G's actual load and PJM's actual load during the five highest PJM peak hours.

In determining the peak load contribution for each of its customers, PSE&G will use the actual hourly meter readings for hourly (interval) metered customers at the time of the five highest peak hours for PJM. For non-hourly metered customers, summer kWh usage and billing demand information for each customer, along with load research (profile) data for customers in the same rate class will be used. There are several steps involved in the peak load calculation.

The first step requires the calculation of a preliminary peak load estimate for each customer based on the available information. For customers without demand meters, such as Rate Schedule RS, this preliminary peak will be based on the individual customer summer energy use

and the summer seasonal load factor (weather adjusted) calculated from the appropriate profile data. For customers with non time-of-day demand meters, such as Rate Schedule GLP, a similar calculation will be performed using appropriate weather adjusted profiled summer load factors, with the exception that the resulting customer peak load estimate will then be compared with the customer's maximum summer measured demand. The lower of the two values will be used for the preliminary peak load estimate. For customers with time-of-day demand meters, such as secondary customers on Rate Schedule LPL, a similar calculation is used utilizing appropriate profiled summer on-peak load factors. The lower of the resulting customer peak load estimate or the summer on-peak measured demand will then be used. For hourly customers such as Rate Schedule HTS, the average of five coincident hourly peaks will be used. The five hours will be based on the same five PJM peak hours as discussed above. If any of these hourly customers were interrupted during the five hours due to Active Load Management (ALM) events, their loads will be adjusted accordingly, or an alternate day peak load will be substituted, so that their subsequent peak is on an "unrestricted" basis. These adjustments are necessary to be consistent with the PJM and LDC loads, which are also on an "unrestricted" basis. The impact of these ALM events will be treated and tracked separately.

The second step calls for the total of these individual loads (with appropriate LDC losses added) to be compared to the PSE&G normalized summer peak load calculated by PJM (approximately 9200 MW as discussed above). A final scaling up or down is performed on each customer's peak load so that the total of the customer peaks equals the 9200 MW.

An estimated peak load will also be assigned to each new customer added since the Summer peak period is based on available information and system average values.

This information, aggregated by Supplier (including PSE&G Basic Generation Service), will be transmitted to PJM. PJM applies a reserve factor and a diversity factor to each Supplier's capacity peak load received from the LDC to determine the Supplier's capacity obligation within the PSE&G zone.

2. Customer Transmission Peak Load Determination

Each customer's transmission load/obligation is calculated using a similar method as described above for capacity. The method above is adjusted as follows: (1) the value assigned by PJM to each zone is based upon the actual load for each zone at the single highest hour of the zone load (not the weather normalized value) and (2) allocation of the transmission peak load to individual customers will be based on the five highest zonal peak loads (not the five highest PJM peak loads).

This information, supplied by the Company and aggregated by Supplier, is transmitted to PJM. No further adjustment is required by PJM.

B. CUSTOMER ENERGY - INTERCHANGE OBLIGATIONS

The PSE&G zonal hourly load of an electric generation supplier ("EGS") supplying load within PSE&G's service territory shall be the sum of the EGS's individual wholesale and retail

customer hourly loads. PSE&G shall report to PJM each day the estimated hourly loads for EGSs. On a monthly basis, PSE&G shall reconcile actual individual customer meter readings and applicable load profile data with the estimated data previously provided on a daily basis for all EGSs and report all hourly differences to PJM by EGS. Individual wholesale and retail customer ("customer") hourly loads for the PSE&G zone shall be determined as follows:

1. Customer usage will be adjusted for losses based on the customer's voltage level. Loss factors will be based on losses contained in PSE&G's then-current Tariff for Electric Service or successor tariff.

2. For hourly (interval) metered customers, the customer's telemetered hourly meter readings will be used in the determination of the customer's estimated hourly load shares. On a monthly basis, PSE&G shall reconcile actual customer meter readings and data previously used in the daily report to PJM for use in reporting any EGS hourly differences to PJM.

3. Each non-hourly metered customer will be assigned a load profile based on the customer's rate schedule for electric service.

4. For non-hourly metered customers, the customer's estimated hourly load shares will be based on the average kWh use of the assigned load profile determined daily from the readings of load research sample meters. On a monthly basis, PSE&G shall reconcile actual individual customer meter readings and applicable load profile data with the estimated hourly data reported daily to PJM. On a monthly basis, PSE&G shall report hourly differences to PJM by EGS.

5. For unmetered rate schedules, the customer's hourly load shares reported will be based on static load research profiles determined for each rate schedule. Load research profiles used for unmetered rate schedules are flat and vary seasonally by on-peak and off-peak time periods.

Information regarding loads, load share calculations, obligations, and load profiles for the PSE&G zone is available on PSE&G's web site.

ATTACHMENT M-2
(ATLANTIC CITY ELECTRIC COMPANY)

PROCEDURES FOR DETERMINATION OF
PEAK LOAD CONTRIBUTIONS AND
HOURLY LOAD OBLIGATIONS FOR RETAIL CUSTOMERS

These calculations are performed on an annual basis and are fixed until the rollover to the new summer data occurs. A complete description of the procedures, together with examples and details on customer load profiles and customer classes, is maintained at Atlantic's web site, www.conectiv.com.

DETERMINATION OF CUSTOMER CAPACITY PEAK LOAD CONTRIBUTIONS

The annual calculation of Customer Capacity Peak Load Contributions (Capacity PLC) is a two-step process: (1) compute the Customer Peak Load Contributions, and (2) scale the Customer PLC's so that they sum to the allocated PJM zonal peak.

1. Five hours of customer loads are gathered, coincident with the time of PJM's five highest daily peak demands during the summer peak. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour quantities for the billing cycles in which the five daily PJM peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage. Using industry standard profiling techniques, and grouped by rate class, weather-normalized kilowatt-hour usage in the five peak load hours is determined for these demand-metered and monthly-metered customers.

2. Interval-metered customer loads are weather normalized if their profiled usage is weather sensitive. Non-interval metered customer loads are scaled according to local weather patterns.

3. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

4. The customer loads are then scaled so that the totals for the Atlantic zone matches the Atlantic unrestricted weather-normalized zonal peak on each of the five PJM (unrestricted) peak load days. The arithmetic average of these (unrestricted) hourly values for the five PJM peak hours is the Customer's Capacity PLC. These Capacity PLC's are again scaled so that the sum of all Customer Capacity PLC's equals the zonal peak allocated by PJM.

Atlantic will aggregate the customer Capacity PLC's daily, by Supplier, and report the data to PJM, as well as make it available to the retail customers. Until individual data is available, new customers are assigned a Capacity PLC according to their profile class.

DETERMINATION OF CUSTOMER NETWORK PEAK LOAD CONTRIBUTIONS

Each customer's Network Peak Load Contribution (Network PLC) is calculated using a method similar to the two-step approach for determining Capacity PLC's. However, instead of using PJM determinants, the hourly loads are associated with the five highest (unrestricted) peaks for the Atlantic zone.

1. For retail customers, five hours of loads are gathered, coincident with the time of the five highest (unrestricted) daily peak demands for the Atlantic zone. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour usage for the billing cycles in which the five daily peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage.

2. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

3. The customer loads are then scaled so their total on each of the five days matches the corresponding unrestricted Atlantic zonal peaks.

4. The arithmetic average of the hourly values at the time of the five Atlantic daily peaks is defined as the customer's Network PLC. These values are again scaled so that the sum of all customers Network PLC's equals the retail portion of the annual Atlantic zonal peak.

Atlantic will aggregate the customer Network PLC's daily, by Supplier, and report the data to PJM on a timetable established by PJM. Until individual data is available, new customers are assigned an average Network PLC for the customer's load profile class.

DETERMINATION OF HOURLY ENERGY OBLIGATIONS

Hourly energy obligations also are addressed in a two-step process. In Settlement A, Atlantic will determine the "day after" energy responsibility. The load characteristics of the operating day in question will be recreated using the known, preliminary, and historically based information available.

1. Preliminary daily read hourly interval meter data will be adjusted for losses using established loss factors, with totals reported for each Supplier.

2. For groups of customers, who do not have interval metering, Atlantic's load profiles will be adjusted to account for factors such as weather and losses. The adjusted profiles will be applied to the profiled customers based on rate class. The assigned profile shall be scaled by customer usage factors, which are based on historical customer energy consumption. These results will be compiled by rate class and Supplier.

3. The aggregate load value for all the adjusted profiled and adjusted interval metered loads will be scaled so that the sum of all hourly loads in the Atlantic zone equals the metered zonal load.

Atlantic will aggregate the hourly energy obligations, by Supplier, and report the totals to PJM as their "day after responsibility".

Settlement B occurs after all actual monthly energy usage data has been processed for the day in question (approximately 45 − 60 days later) and occurs between the Supplier and PJM.

1. Atlantic will calculate the difference between the final hourly load obligation and the "day after" estimated load obligation previously determined in Settlement A.

2. After a calendar month becomes fully metered, Atlantic will compute and submit to PJM the complete hourly adjustments for that month.

Atlantic will aggregate the hourly energy adjustments, by Supplier, and submit to PJM a calendar-month file containing Supplier hourly energy obligation amounts. PJM will then issue a final bill reflecting any adjustments.

If any adjustments need to be made to a customer's data after the regular monthly reconciliation in Settlement B, then the Parties involved will agree on the adjustment. Atlantic will then forward the information to PJM. PJM will place the final adjustments on the appropriate Party's bill. Any disputes shall be resolved through the PJM Dispute Resolution Process.

ATTACHMENT M-2
(DELMARVA POWER & LIGHT COMPANY)

PROCEDURES FOR DETERMINATION OF
PEAK LOAD CONTRIBUTIONS AND
HOURLY LOAD OBLIGATIONS FOR RETAIL CUSTOMERS

These calculations are performed on an annual basis and are fixed until the rollover to the new summer data occurs. A complete description of the procedures, together with examples and details on customer load profiles and customer classes, is maintained at Delmarva's web site, www.conectiv.com.

DETERMINATION OF CUSTOMER CAPACITY PEAK LOAD CONTRIBUTIONS

The annual calculation of Customer Capacity Peak Load Contributions (Capacity PLC) is a two-step process: (1) compute the Customer Peak Load Contributions, and (2) scale the Customer PLC's so that they sum to the allocated PJM zonal peak.

1. Five hours of customer loads are gathered, coincident with the time of PJM's five highest daily peak demands during the summer peak. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour quantities for the billing cycles in which the five daily PJM peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage. Using industry standard profiling techniques, and grouped by rate class, weather-normalized kilowatt-hour usage in the five peak load hours is determined for these demand-metered and monthly-metered customers.

2. Interval-metered customer loads are weather normalized if their profiled usage is weather sensitive. Non-interval metered customer loads are scaled according to local weather patterns.

3. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

4. The customer loads are then scaled so that the total for the Delmarva zone matches the Delmarva unrestricted weather-normalized zonal peak on each of the five PJM (unrestricted) peak load days. The arithmetic average of these (unrestricted) hourly values for the five PJM peak hours is the Customer's Capacity PLC. These Capacity PLC's are again scaled so that the sum of all Customer Capacity PLC's equals the zonal peak allocated by PJM.

Delmarva will aggregate the customer Capacity PLC's daily, by Supplier, and report the data to PJM, as well as make it available to the retail customers. Until individual data is available, new customers are assigned a Capacity PLC according to their profile class.

DETERMINATION OF CUSTOMER NETWORK PEAK LOAD CONTRIBUTIONS

Each customer's Network Peak Load Contribution (Network PLC) is calculated using a method similar to the two-step approach for determining Capacity PLC's. However, instead of using PJM determinants, the hourly loads are associated with the five highest (unrestricted) peaks for the Delmarva zone.

1. For retail customers, five hours of loads are gathered, coincident with the time of the five highest (unrestricted) daily peak demands for the Delmarva zone. Actual metered loads for (hourly) interval-metered customer are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour usage for the billing cycles in which the five daily peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage.

2. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

3. The customer loads are then scaled so their total on each of the five days matches the corresponding unrestricted Delmarva zonal peaks.

4. The arithmetic average of the hourly values at the time of the five Delmarva daily peaks is defined as the customer's Network PLC. These values are again scaled so that the sum of all customer Network PLC's equals the retail portion of the annual Delmarva zonal peak.

Delmarva will aggregate the customer Network PLC's daily, by Supplier, and report the data to PJM on a timetable established by PJM. Until individual data is available, new customers are assigned an average Network PLC for the customer's load profile class.

DETERMINATION OF HOURLY ENERGY OBLIGATIONS

Hourly energy obligations are addressed in a two-step process. In Settlement A, Delmarva will determine the "day after" energy responsibility. The load characteristics of the operating day in question will be recreated using the known, preliminary, and historically based information available.

1. Preliminary daily read hourly interval meter data will be adjusted for losses using established loss factors, with totals reported for each Supplier.

2. For groups of customers, who do not have interval metering, Delmarva's load profiles will be adjusted to account for factors such as weather and losses. The adjusted profiles will be applied to the profiled customers based on rate class. The assigned profile shall be scaled by customer usage factors, which are based on historical customer energy consumption. These results will be compiled by rate class and Supplier.

3. The aggregate load value for all the adjusted profiled and adjusted interval metered loads will be scaled so that the sum of all hourly loads in the Delmarva zone equals the metered zonal load.

Delmarva will aggregate the hourly energy obligations, by Supplier, and report the totals to PJM as their "day after responsibility".

Settlement B occurs after all actual monthly energy usage data has been processed for the day in question (approximately 45 − 60 days later) and occurs between the Supplier and PJM.

1. Delmarva will calculate the difference between the final hourly load obligation and the "day after" estimated load obligation previously determined in Settlement A.

2. After a calendar month becomes fully metered, Delmarva will compute and submit to PJM the complete hourly adjustments for that month.

Delmarva will aggregate the hourly energy adjustments, by Supplier, and submit to PJM a calendar-month file containing Supplier hourly energy obligation amounts. PJM will then issue a final bill reflecting any adjustments.

If any adjustments need to be made to a customer's data after the regular monthly reconciliation in Settlement B, then the Parties involved will agree on the adjustment. Delmarva will then forward the information to PJM. PJM will place the final adjustments on the appropriate Party's bill. Any disputes shall be resolved through the PJM Dispute Resolution Process.

ATTACHMENT M-2
(DELMARVA POWER & LIGHT COMPANY)

PROCEDURES FOR DETERMINATION OF
PEAK LOAD CONTRIBUTIONS AND
HOURLY LOAD OBLIGATIONS FOR RETAIL CUSTOMERS

These calculations are performed on an annual basis and are fixed until the rollover to the new summer data occurs. A complete description of the procedures, together with examples and details on customer load profiles and customer classes, is maintained at Delmarva's web site, www.conectiv.com.

DETERMINATION OF CUSTOMER CAPACITY PEAK LOAD CONTRIBUTIONS

The annual calculation of Customer Capacity Peak Load Contributions (Capacity PLC) is a two-step process: (1) compute the Customer Peak Load Contributions, and (2) scale the Customer PLC's so that they sum to the allocated PJM zonal peak.

1. Five hours of customer loads are gathered, coincident with the time of PJM's five highest daily peak demands during the summer peak. Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour quantities for the billing cycles in which the five daily PJM peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage. Using industry standard profiling techniques, and grouped by rate class, weather-normalized kilowatt-hour usage in the five peak load hours is determined for these demand-metered and monthly-metered customers.

2. Interval-metered customer loads are weather normalized if their profiled usage is weather sensitive. Non-interval metered customer loads are scaled according to local weather patterns.

3. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

4. The customer loads are then scaled so that the total for the Delmarva zone matches the Delmarva unrestricted weather-normalized zonal peak on each of the five PJM (unrestricted) peak load days. The arithmetic average of these (unrestricted) hourly values for the five PJM peak hours is the Customer's Capacity PLC. These Capacity PLC's are again scaled so that the sum of all Customer Capacity PLC's equals the zonal peak allocated by PJM.

Delmarva will aggregate the customer Capacity PLC's daily, by Supplier, and report the data to PJM, as well as make it available to the retail customers. Until individual data is available, new customers are assigned a Capacity PLC according to their profile class.

DETERMINATION OF CUSTOMER NETWORK PEAK LOAD CONTRIBUTIONS

Each customer's Network Peak Load Contribution (Network PLC) is calculated using a method similar to the two-step approach for determining Capacity PLC's. However, instead of using PJM determinants, the hourly loads are associated with the five highest (unrestricted) peaks for the Delmarva zone.

1. For retail customers, five hours of loads are gathered, coincident with the time of the five highest (unrestricted) daily peak demands for the Delmarva zone. Actual metered loads for (hourly) interval-metered customer are adjusted to include any load curtailed as a result of active load management initiatives, voltage reductions, manual load dumps, or other load restrictions. These adjusted loads are referred to as "unrestricted loads". For non-interval metered customers (demand-metered and monthly-metered), the customers' loads are the hourly profiled kilowatt-hour usage for the billing cycles in which the five daily peaks occurred. Individual customer loads are scaled up or down, using a ratio of the customer's monthly usage to the profiled class' average monthly usage.

2. Each customer's loads are adjusted for losses, consistent with the customer's Service Agreement and the loss factors in the most recent state commission filing of loss factors by voltage classes.

3. The customer loads are then scaled so their total on each of the five days matches the corresponding unrestricted Delmarva zonal peaks.

4. The arithmetic average of the hourly values at the time of the five Delmarva daily peaks is defined as the customer's Network PLC. These values are again scaled so that the sum of all customer Network PLC's equals the retail portion of the annual Delmarva zonal peak.

Delmarva will aggregate the customer Network PLC's daily, by Supplier, and report the data to PJM on a timetable established by PJM. Until individual data is available, new customers are assigned an average Network PLC for the customer's load profile class.

DETERMINATION OF HOURLY ENERGY OBLIGATIONS

Hourly energy obligations are addressed in a two-step process. In Settlement A, Delmarva will determine the "day after" energy responsibility. The load characteristics of the operating day in question will be recreated using the known, preliminary, and historically based information available.

1. Preliminary daily read hourly interval meter data will be adjusted for losses using established loss factors, with totals reported for each Supplier.

2. For groups of customers, who do not have interval metering other interval meters which are not read daily, Delmarva's load profiles will be adjusted to account for factors such as weather and losses. The adjusted profiles will be applied to the profiled customers based on rate class. The assigned profile shall be scaled by customer usage factors, which are based on historical customer energy consumption. These results will be compiled by rate class and Supplier.

3. The aggregate load value for all the adjusted profiled and adjusted interval metered loads will be scaled so that the sum of all hourly loads in the Delmarva zone equals the metered zonal load.

Delmarva will aggregate the hourly energy obligations, by Supplier, and report the totals to PJM as their "day after responsibility".

Settlement B occurs after all actual monthly energy usage data has been processed for the day in question (approximately 45 − 60 days later) and occurs between the Supplier and PJM.

1. Delmarva will calculate the difference between the final hourly load obligation and the "day after" estimated load obligation previously determined in Settlement A.

2. After a calendar month becomes fully metered, Delmarva will compute and submit to PJM the complete hourly adjustments for that month.

Delmarva will aggregate the hourly energy adjustments, by Supplier, and submit to PJM a calendar-month file containing Supplier hourly energy obligation amounts. PJM will then issue a final bill reflecting any adjustments.

If any adjustments need to be made to a customer's data after the regular monthly reconciliation in Settlement B, then the Parties involved will agree on the adjustment. Delmarva will then forward the information to PJM. PJM will place the final adjustments on the appropriate Party's bill. Any disputes shall be resolved through the PJM Dispute Resolution Process.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider or ILR Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

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

2.4 Base Offer Segment

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

2.5 Base Residual Auction

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

2.6 Buy Bid

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

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a PJM Member that has the capability to reduce load, or that aggregates customers capable of reducing load. The Demand Resource Provider shall notify the Office of the Interconnection whether such load reduction is provided by a Limited Demand Resource, Extended Summer Demand Resource or an Annual Demand Resource. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource.

2.23 EFORd

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

2.24 Energy Efficiency Resource

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

2.24A Extended Summer Demand Resource

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

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Extended Summer Demand Resource Reliability Target

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

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Extended Summer Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 [Reserved]

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A Final Zonal ILR Price

"Final Zonal ILR Price" shall mean the Adjusted Zonal Capacity Price after the Second Incremental Auction, less the amount paid in CTR credits per MW of load in the Zone in which the ILR is to be certified.

2.27 First Incremental Auction

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

2.28 Forecast Pool Requirement

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

2.29 Forecast RTO ILR Obligation

"Forecast RTO ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the PJM Region times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region, for use in Delivery Years through May 31, 2012.

2.30 Forecast Zonal ILR Obligation

"Forecast Zonal ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the Zone times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in such Zone, for use in Delivery Years through May 31, 2012.

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 ILR Forecast

"ILR Forecast" shall mean, for any Delivery Year ending on or before May 31, 2012, the average annual megawatt quantity of ILR certified for the five Planning Periods preceding the date of the forecast; provided, however, that before such data becomes available for five Delivery Years under the Reliability Pricing Model, comparable data on Active Load Management (as defined in the preexisting reliability assurance agreements) from up to five prior Planning Periods shall be substituted as necessary; and provided further that, for transmission zones that were integrated into the PJM Region less than five years prior to the conduct of the Base Residual Auction for the Delivery Year, data on incremental load subject to mandatory interruption by Electric Distribution Companies within such zones shall be substituted as necessary.

2.33 ILR Provider

"ILR Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as such term is defined in the PJM Operating Agreement, may be an ILR Provider, provided it obtains certification of its load reduction capability as ILR.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Interruptible Load for Reliability (ILR)

"Interruptible Load for Reliability" or "ILR" shall have the meaning specified in the Reliability Assurance Agreement.

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for the PJM Region or such LDA.

As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; and ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result. Second, PJM adopts the lower result from these two tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.37 Load Serving Entity (LSE)

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

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

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

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Short-Term Resource Procurement Target for the PJM Region in Unforced Capacity] minus [the Extended Summer Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the Short-Term Resource Procurement Target for such LDA in Unforced Capacity] minus [the LDA CETL] minus [the Extended Summer Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual

Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Short-Term Resource Procurement Target for the RTO in Unforced Capacity] minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the Short-Term Resource Procurement Target for the LDA in Unforced Capacity] minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

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

2.43A Nominated Energy Efficiency Value

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

2.44 Nominated ILR Value

"Nominated ILR Value" shall mean the amount of load reduction that an ILR resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For ILR, the maximum Nominated ILR Capacity Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the ILR is certified.

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is dispatched in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average real-time LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be dispatched independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be dispatched for such block.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 10,500 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.61 Resource Substitution Charge

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

2.61A Scheduled Incremental Auctions

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

2.62 Second Incremental Auction

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

2.63 Sell Offer

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

2.64 [Reserved for Future Use]

2.65 Self-Supply

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

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the

Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

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

2.66 Third Incremental Auction

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

2.67 Transition Adder

"Transition Adder" shall mean a component of a Sell Offer permitted for certain Capacity Market Sellers for the Transition Period, as set forth in section 17.

2.68 Transition Period

"Transition Period" shall mean the four-year period consisting of the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010.

2.69 Unforced Capacity

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

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net

Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.70 Variable Resource Requirement Curve

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

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.3A Locational UCAP Bilateral Transactions

A Member that has committed capacity through an RPM Auction for a Delivery Year may purchase Locational UCAP as replacement capacity from a Member with available uncommitted capacity for such Delivery Year in accordance with the terms of this section and the PJM Manuals. Locational UCAP may not be sold or purchased prior to the date that the final EFORD is established for such Delivery Year, and if designated to PJM by the Locational UCAP Seller as sold prior to the Third Incremental Auction for a Delivery Year must be confirmed by the buyer prior to such Third Incremental Auction as purchased for replacement capacity, or such transaction shall be rejected. In accordance with procedures specified in the PJM Manuals, the parties to a Locational UCAP transaction must notify PJM of such transaction, which notification must specify: i) the buyer, ii) the Locational UCAP Seller, iii) the start and end dates of the transaction (which may not be retroactive), iv) the Locational UCAP amount (no less than 0.1 megawatts), v) the demand or generation resource with available uncommitted capacity that is the basis for the sale, and vi) the Locational Delivery Area in which the resource is located. The Locational UCAP Seller shall be responsible for any charges imposed under sections 7, 8, 9, 10, 11, or 13, as applicable, for such Delivery Year, with respect to the increment of capacity sold as Locational UCAP; any other settlement of charges under the Locational UCAP transaction shall be between the parties. A purchaser of Locational UCAP may not offer such capacity into an RPM Auction.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, in accordance with the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Annual Demand Resource, Extended Summer Demand Resource, Limited Demand Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered. The Office of the Interconnection shall, in both cases, convert such value to an Unforced Capacity basis by multiplying such value by the DR Factor times the Forecast Pool Requirement. Demand Resources shall specify the LDA in which the Demand Resource is located, including the

location of such resource within any Zone that includes more than one LDA as identified on Schedule 10.1 of the RAA.

e) A Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Attachment Q to this Tariff, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Section 6.6 of Attachment DD, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

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 Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter 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.

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: [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 Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- 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 Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; 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 Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

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 Reliability Council 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 EMAAC, SWMAAC and MAAC 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, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $112,868 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")	122,040
BGE, PEPCO ("CONE Area 2")	112,868
AEP, Dayton, ComEd, APS, DQL, ATSI ("CONE Area 3")	115,479
PPL, MetEd, Penelec ("CONE Area 4")	112,868
Dominion ("CONE Area 5")	112,868

B) Beginning with the 2013-2014 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.

(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 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 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 Market 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 transmission zone in which such 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) Adjustment to Net Energy and Ancillary Services Revenue Offset

Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the

applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.

vii) 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.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Attachment M and Attachment - M Appendix to this Tariff and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) By no later than 90 days (or such other time period as established for purposes of the Transition Period) prior to the conduct of the Base Residual Auction and each Incremental Auction for such Delivery Year, the Office of the Interconnection shall post or continue to post the results of the Market Monitoring Unit's application of the Preliminary Market Structure Screen determined pursuant to section II.D of Attachment M - Appendix.

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Tests

(a) Preliminary Market Structure Screen.

The Market Monitoring Unit shall apply the Preliminary Market Structure Screen pursuant to section II.D of Attachment M - Appendix. Potential Capacity Market Sellers owning or controlling any existing Generation Capacity Resources in the PJM Region shall be required to provide to the Market Monitoring Unit the additional information specified in section II.D of Attachment M - Appendix if such Generation Capacity is located in an LDA, "Unconstrained

LDA Group" (as defined in Attachment M - Appendix), or the entire PJM Region that fails the Preliminary Market Structure Screen, as applied pursuant to section II.D below.

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or priced based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW-day of installed capacity, applicable to price-quantity offers within the Base Offer Segment for an existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW of unforced capacity. During the first three Delivery Years of the Transition Period, the Market Seller Offer Cap shall be increased for Sell Offers submitted by eligible Capacity Market Sellers in any Unconstrained LDA Group by the Transition Adder set forth in section 17.5 of this Attachment. The Market Seller Offer Cap for an existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in section II.E.3 of Attachment M- Appendix.

(b) For each existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the level of the Market Seller Offer Cap applicable to each resource. The Capacity Market Seller must promptly address any concerns identified by the

Market Monitoring Unit regarding the data and documentation provided, review the proposed Market Seller Offer Cap, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap.

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section II.E of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the level of a Market Seller Offer Cap, the Office of the Interconnection shall make its own determination of the level of the Market Seller Offer Cap based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits a Sell Offer that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the level of the Market Seller Offer Cap, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit a Sell Offer consistent with the Office of the Interconnection's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit a Sell Offer consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.E of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit a Sell Offer that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.4 and in section II.E of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) For any Third Incremental Auction, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to paragraph (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the deadline for submission of such offers in the applicable auction. Such resources are Existing Generation Capacity Resources in the auctions for any Delivery Year following the Delivery Year for which such resource cleared an RPM Auction. Such resources may receive certain price assurances for the two Delivery Years immediately following the first Delivery Year of service under certain conditions as set forth in section 5.14 of this Attachment. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

(B) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) submitted for the first year in which such resources qualify as Planned Generation Capacity Resources shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding

the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold. The Office of the Interconnection then shall clear the auction with such revised Sell Offer in place.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Section 5.6.6 of Attachment DD of the Tariff. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in Section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Section II.C.1 of Attachment M – Appendix of the Tariff, but is omitted

therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the maximum EFORd applicable to each resource. The maximum EFORd that may be used in a Sell Offer for Base Residual Auctions, First Incremental Auctions and Second Incremental Auctions, and for Conditional Incremental Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction. The maximum EFORd that may be used in a Sell Offer for Third Incremental Auctions, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the proposed maximum EFORd, and attempt to reach agreement with the Market Monitoring Unit on the maximum level of the EFORd

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below and section II.E of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the EFORd, the Office of the Interconnection shall make its own determination of the maximum level of the EFORd based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits an EFORd that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the maximum level of the EFORd, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.C of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.6 and in section II.C of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction.However, generation resource may qualify for an exception to the must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the must-offer requirement shall first submit such request to the Market Monitoring Unit for evaluation. A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD and the Office of the Interconnection agrees with this determination, or, (ii) the potential Capacity Market Seller and the Market Monitoring Unit cannot come to agreement on whether a Generation Capacity Resource should be removed from PJM Capacity Resource status or satisfied the criteria for an exception to the must-offer requirement, the potential Capacity Market Seller has submitted its request to remove the resource from PJM Capacity Resource status to the Office of the Interconnection, and the Office of the Interconnection has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of Section 6.6.

After the Market Monitoring Unit has made its determination of whether a resource has satisfied the must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Section II.C.4 of Attachment M – Appendix, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved or denied by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit that it disagrees with the Market Monitoring Unit's determination. After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the must-offer requirement and prior to the date on which bidding commences for the applicable RPM Auction, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis

of an identified exception. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Attachment M and Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the must-offer requirement, into an RPM

Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit no later than four months prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that fails the Preliminary Market Structure Screen (or, if such region fails the screen, potential auction participants in the entire PJM Region) shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than two months prior to the conduct of such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. Any Sell Offer submitted in any auction that is inconsistent with any commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required promptly to resubmit a Sell Offer that complies with such commitments. If the Capacity Market Seller does not timely resubmit its Sell Offer, it shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default price equal to the maximum price for the class of resource determined under section (c)(ii) above. The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 and section II.H of Attachment M - Appendix. The default Avoidable Cost Rates referenced in section (c)(ii) above are as set forth in the tables below for any auction conducted after September 1, 2009 for any Delivery Year through the 2012-2013 Delivery Year. To determine the default ACR values for the 2013-2014 and subsequent Delivery Years, the Office of the Interconnection shall multiply the ACR values for the immediately preceding Delivery Year by a factor equal to the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission, as calculated by the Office of the Interconnection and posted to its Web site; provided, however, that after the Handy-Whitman indexing methodology has been employed to determine the default ACR values for the RPM Auctions for three consecutive Delivery Years, the Office of the Interconnection shall: i) review the default ACR values to determine whether any changes other than those produced by such methodology are warranted for subsequent Delivery Years (including seeking the analysis and advice of the Market Monitoring Unit on such matter) and report its conclusions to the Members in writing no later than four months after the Base Residual Auction for the third such Delivery Year; and ii) file with FERC resulting changes, if any, to this section no later than seven months after such Base Residual Auction, to be effective for the Base Residual Auction for the following Delivery Year; provided further, that nothing herein precludes the Office of the Interconnection from filing with FERC changes to the default ACR values or any other provision of this section prior to the deadline stated in the previous clause, or at any other time. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

Technology Classes Not Likely to be the Marginal Price Setting Resource						
Technology	**2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)**	**2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)**	**2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)**	**2012 -2013 Retirement Avoidable Cost Rate ($/MW-Day)**
Nuclear	N/a	N/a	N/a	N/a	N/a	N/a
Pumped Storage	$20.77	$29.17	$21.72	$30.50	$22.71	$31.89
Hydro	$71.01	$92.87	$74.24	$97.10	$77.62	$101.52
Sub-Critical Coal	$170.48	$188.98	$178.24	$197.58	$186.35	$206.57
Super Critical Coal	$176.13	$192.65	$184.15	$201.42	$192.53	$210.59
Waste Coal - Small	$224.83	$272.31	$235.06	$284.70	$245.75	$297.65
Waste Coal – Large	$83.15	$100.45	$86.94	$105.02	$90.89	$109.80
Wind	N/a	N/a	N/a	N/a	N/a	N/a

Maximum Avoidable Cost Rates by Technology Class

Technology	2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)	2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)	2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)	2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)	2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)	2012-2013 Retirement Avoidable Cost Rate ($/MW-Day)
CC- 2 on 1 Frame F	$30.92	$43.86	$32.33	$45.85	$33.80	$47.94
CC- 3 on 1 Frame E/Siemens	$34.33	$46.48	$35.89	$48.60	$37.52	$50.81
CC – 3 or More on 1 or More Frame F	$26.76	$37.16	$27.98	$38.85	$29.26	$40.62
CC-NUG Cogen. Frame B or E Technology	$114.93	$154.43	$120.16	$161.45	$125.62	$168.80
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$24.57	$32.68	$25.69	$34.17	$26.86	$35.73
CT - 1st & Gen. Frame B	$24.28	$32.41	$25.38	$33.87	$26.54	$35.42
CT - 2nd Gen. Frame E	$23.08	$30.89	$24.13	$32.29	$25.23	$33.76
CT - 3rd Gen. Aero (GE LM 6000)	$55.87	$82.36	$58.42	$86.10	$61.07	$90.02
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$29.30	$43.20	$30.64	$45.17	$32.03	$47.23
CT - 3rd Gen. Frame F	$23.69	$34.12	$24.77	$35.68	$25.90	$37.30
Diesel	$26.29	$33.39	$27.49	$34.91	$28.74	$36.49
Oil and Gas Steam	$65.21	$79.39	$68.18	$83.01	$71.28	$86.78

After the Market Monitoring Unit conducts its annual review of the table of default Avoided Cost Rates included in section 6.7(c) above in accordance with the procedure specified in section II.H of Attachment M – Appendix, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file its values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit relevant cost data concerning each data item specified as set forth in section 6. If cost data is not available at the time of submission for the time periods specified in section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate. The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(c) below.

iii. Projected PJM Market Revenues, as defined by section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, a Capacity Market Seller must timely submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-

Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

    - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

    - **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

    - **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

    - **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

    - **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve

months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

- **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 16 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. A Sell Offer submitted in the BRA for either or both of the 2007-2008 and 2008-2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the

clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Year Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Year Plus Option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under section 5.14(c) of this Attachment.

- ARPIR (Avoidable Refunds of Project Investment Reimbursements) consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Part V, Section 118 of this Tariff or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Part V, Section 119 of the Tariff and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

ATTACHMENT II

MTEP PROJECT COST RECOVERY FOR ATSI ZONE

I. Definitions

A. ATSI - American Transmission Systems, Incorporated.

B. Midwest ISO or MISO – The Midwest Independent Transmission System Operator, Inc.

C. Midwest ISO Tariff - The Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff.

D. [Reserved]

E. MTEP – The Midwest ISO Transmission Expansion Plan established pursuant to Attachment FF of the Midwest ISO Tariff.

F. MTEP Project – A transmission project constructed by ATSI pursuant to Attachment FF of the Midwest ISO Tariff. For purposes of this Attachment II, MTEP Projects are limited to those projects listed in Section V of this Attachment.

II. Introduction and Purpose

This Attachment II addresses the manner in which the Office of the Interconnection will distribute revenues received from the Midwest ISO for MTEP Projects constructed by ATSI.

III. [Reserved]

IV. ATSI MTEP Project Revenue Requirements Allocated to Midwest ISO Zones

A. Derivation of Annual Revenue Requirements

Under the methodology provided under Attachment H–21 to this Tariff, ATSI will periodically update the annual revenue requirements for MTEP Projects constructed by ATSI. No later than May 1 each year, ATSI shall provide these updated revenue requirements to the Midwest ISO for the upcoming June 1 – May 31 rate year. The list of MTEP Projects for purposes of this Section IV.A is provided in Section V.B.

B. Allocation of Annual Revenue Requirements to Midwest ISO Zones

The portion of the annual revenue requirements derived under Section IV.A that will be recovered from transmission customers taking transmission service in the Midwest ISO shall be calculated by the Midwest ISO by multiplying each MTEP Project's revenue requirements derived in Section IV.A by the percentage allocable to each applicable Midwest ISO zone in accordance with the allocation methodology approved by FERC

with respect to that MTEP Project, at the time the project was approved by the Midwest ISO Board of Directors.

C. Monthly Revenue Requirements Owed from the Midwest ISO Zones

Each month, and pursuant to agreed upon settlement procedures, the Midwest ISO shall remit an amount to the Office of the Interconnection from revenues collected by the Midwest ISO in proportion to ATSI's annual pro-rata share of the total Network Upgrade Charge as described in the Midwest ISO Schedule 26.

D. Revenue Distribution from Payments Made by Transmission Customers in the Midwest ISO

Provided the Midwest ISO remits to the Office of the Interconnection the amount of revenue requirements owed ATSI pursuant to Section IV.C, PJM shall credit 100% of the amounts to ATSI.

V. MTEP Projects

A. [Reserved]

B. MTEP Projects Constructed by ATSI

Projects ID – Project Name

890 - North Medina 345/138 kV Substation

1326- Capacitor Banks at Harding and Juniper 345 kV

AMENDED AND RESTATED

OPERATING AGREEMENT

OF

PJM INTERCONNECTION, L.L.C.

AMENDED AND RESTATED
OPERATING AGREEMENT
OF
PJM INTERCONNECTION, L.L.C.

This Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of this 2nd day of June, 1997, amends and restates as of the Effective Date the Operating Agreement of PJM Interconnection, L.L.C. filed with the FERC on April 2, 1997, as amended.

WHEREAS, certain of the Members have previously entered into an agreement, originally dated September 26, 1956, as amended and supplemented up to and including December 31, 1996, stating "their respective rights and obligations with respect to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems" (such agreement as amended and supplemented being referred to as the "Original PJM Agreement"), and which coordinated operations and interchange came to be known as the PJM Interconnection; and

WHEREAS, pursuant to a resolution of June 16, 1993, an unincorporated association comprised of the parties to the Original PJM Agreement was formed for the purpose of implementation of the Original PJM Agreement as it then existed and as it subsequently has been amended and supplemented, such association being known as the "PJM Interconnection Association"; and

WHEREAS, because of changes in federal law and policy, the Original PJM Agreement, together with other documents and agreements, was amended, restated and submitted to FERC on December 31, 1996 to restructure fundamental aspects of the operation of the Interconnection; and

WHEREAS, so that the provisions of the Original PJM Agreement could be placed into effect consistent with a February 28, 1997 order of FERC, including those provisions related to the governance of the Interconnection, the parties to the Original PJM Agreement, along with the other interested parties, approved the conversion of the PJM Interconnection Association into the LLC pursuant to the provisions of the Delaware Limited Liability Company Act, as amended (the "Delaware LLC Act"), pursuant to a Certificate of Formation (the "Certificate of Formation") and a Certificate of Conversion (the "Certificate of Conversion"), each filed with the Delaware Secretary of State (the "Recording Office") on March 31, 1997; and

WHEREAS, the Members wish to amend and restate the Operating Agreement of PJM Interconnection, L.L.C. adopted in connection with the formation of the LLC and as in effect immediately prior to the Effective Date in the form set forth below; and

WHEREAS, the Members intend to form an Independent System Operator in accordance with the regulations of the Federal Energy Regulatory Commission; and

WHEREAS, the Members wish to amend and restate the Operating Agreement to provide for expansion of the operations of PJM Interconnection, L.L.C. into additional Control Areas.

Now, therefore, in consideration of the foregoing, and of the covenants and agreements hereinafter set forth, the Members hereby agree as follows:

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The total Transmission Loss Charges accumulated by PJMSettlement in any hour shall be distributed pro-rata to each Network Service User and Transmission Customer in proportion to its ratio shares of the total MWhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, or the total exports of MWh of energy from the PJM Region (that paid for transmission service during such hour). Exports of energy for which Non-Firm Point-to-Point Transmission Service was utilized and for which the Non-Firm Point-to-Point Transmission Service rate was paid will receive an allocation of the total Transmission Loss Charges based on a percentage of the MWh of energy exported on such service, determined by the ratio of Non-Firm Point-to-Point Transmission Service rate to Firm Point-to-Point Transmission Service rate.

ARTICLE 1 -- DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

1.1 Agreement

Agreement shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

1.1A Annual Demand Resource

Annual Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1 .2 Applicable Regional Reliability Council

Applicable Regional Reliability Council shall have the same meaning as in the PJM Tariff.

1.3 Base Residual Auction

Base Residual Auction shall have the same meaning as in Attachment DD to the PJM Tariff.

1.4 Behind The Meter Generation

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

1.5 Black Start Capability

Black Start Capability shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

1.6 Capacity Emergency Transfer Objective ("CETO")

Capacity Emergency Transfer Objective ("CETO") shall mean the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be calculated based in part on EFORD determined in accordance with Paragraph C of Schedule 5.

1.7 Capacity Emergency Transmission Limit ("CETL")

Capacity Emergency Transmission Limit ("CETL") shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

1.8 Capacity Resources

Capacity Resources shall mean megawatts of (i) net capacity from existing or Planned Generation Capacity Resources meeting the requirements of Schedules 9 and 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under this Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from existing or Planned Generation Capacity Resources within the PJM Region not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10; and (iii) load reduction capability provided by Demand Resources, Energy Efficiency Resources, or ILR that are accredited to the PJM Region pursuant to the procedures set forth in Schedule 6.

1.9 Capacity Transfer Right

Capacity Transfer Right shall have the meaning specified in Attachment DD to the PJM Tariff.

1.10 Control Area

Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and Applicable Regional Reliability Councils;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.11 Daily Unforced Capacity Obligation

Daily Unforced Capacity Obligation shall have the meaning set forth in Schedule 8 or, as to an FRR Entity, in Schedule 8.1.

1.12 Delivery Year

Delivery Year shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Attachment DD to the Tariff or pursuant to an FRR Capacity Plan.

1.13 Demand Resource

Demand Resource or "DR" shall mean a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan. As set forth in Schedule 6, a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may be an existing demand response resource or a Planned Demand Resource.

1.14 Demand Resource Provider

Demand Resource Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.15 DR Factor

DR Factor shall mean that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource or ILR in accordance with Schedule 6.

1.16 East RAA

East RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM Region, PJM Rate Schedule FERC No. 27.

1.17 Electric Cooperative

Electric Cooperative shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

1.18 Electric Distributor

Electric Distributor shall mean an entity that owns or leases with rights equivalent to ownership electric distribution facilities that are providing electric distribution service to electric load within the PJM Region.

1.19 Emergency

Emergency shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

1.20 End-Use Customer

End-Use Customer shall mean a Member that is a retail end-user of electricity within the PJM Region.

1.20A Energy Efficiency Resource

Energy Efficiency Resource shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Schedule 6 of this Agreement and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described in Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

1.20B Existing Generation Capacity Resource

Existing Generation Capacity Resource shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

1.20C Extended Summer Demand Resource

Extended Summer Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.21 Facilities Study Agreement

Facilities Study Agreement shall have the same meaning as in the PJM Tariff

1.22 FERC

FERC shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department.

1.23 Firm Point-To-Point Transmission Service

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

1.24 Firm Transmission Service

Firm Transmission Service shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

1.25 Fixed Resource Requirement Alternative or FRR Alternative

Fixed Resource Requirement Alternative or FRR Alternative shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in Schedule 8.1 to this Agreement.

1.26 Forecast Pool Requirement

Forecast Pool Requirement shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.27 Forecast RTO ILR Obligation

Forecast RTO ILR Obligation shall have the same meaning as in the PJM Tariff.

1.28 Forecast Zonal ILR Obligation

Forecast Zonal ILR Obligation shall have the same meaning as in the PJM Tariff.

1.29 FRR Capacity Plan

FRR Capacity Plan shall mean a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in Schedule 8.1 to this Agreement.

1.30 FRR Entity

FRR Entity shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

1.31 FRR Service Area

FRR Service Area shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load

(including load growth) within such area excluding the load of Single-Customer LSEs that are FRR Entities. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

1.32 Full Requirements Service

Full Requirements Service shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.33 Generation Capacity Resource

Generation Capacity Resource shall mean a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of this Agreement. A Generation Capacity Resource may be an *E*xisting Generation Capacity Resource or a Planned Generation Capacity Resource.

1.34 Generation Owner

Generation Owner shall mean a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

1.35 Generator Forced Outage

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

1.36 Generator Maintenance Outage

Generator Maintenance Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

1.37 Generator Planned Outage

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

1.38 Good Utility Practice

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

1.39 ILR Provider

ILR Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.40 Incremental Auction

Incremental Auction shall mean the First Incremental Auction, the Second Incremental Auction, the Third Incremental Auction, or the Conditional Incremental Auction, each as defined in Attachment DD to the PJM Tariff.

1.41 Interconnection Agreement

Interconnection Agreement shall have the same meaning as in the PJM Tariff.

1.42 Interruptible Load for Reliability, or ILR

Interruptible Load for Reliability, or ILR, shall mean a resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that is certified by PJM no later than three months prior to a Delivery Year. At a minimum, ILR shall be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the ILR shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time in the corresponding Delivery Year.

1.43 IOU

IOU shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

1.43A Limited Demand Resource

Limited Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.44 Load Serving Entity or LSE

Load Serving Entity or LSE shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

1.45 Locational Reliability Charge

Locational Reliability Charge shall mean the charge determined pursuant to Schedule 8.

1.46 Markets and Reliability Committee

Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.47 Member

Member shall mean an entity that satisfies the requirements of Sections 1.24 and 11.6 of the PJM Operating Agreement. In accordance with Article 4 of this Agreement, each Party to this Agreement also is a Member.

1.48 Members Committee

Members Committee shall mean the committee specified in Section 8 of the PJM Operating Agreement composed of the representatives of all the Members.

1.49 NERC

NERC shall mean the North American Electric Reliability Council or any successor thereto.

1.50 Network Resources

Network Resources shall have the meaning set forth in the PJM Tariff.

1.51 Network Transmission Service

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

1.52 Nominated Demand Resource Value

Nominated Demand Resource Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.53 Nominated ILR Value

Nominated ILR Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.54 Non-Retail Behind the Meter Generation

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

1.55 Obligation Peak Load

Obligation Peak Load shall have the meaning specified in Schedule 8 of this Agreement.

1.56 Office of the Interconnection

Office of the Interconnection shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

1.57 Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement

Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement shall mean that certain agreement, dated April 1, 1997 and as amended and restated June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.58 Operating Reserve

Operating Reserve shall mean the amount of generating capacity scheduled to be available for a specified period of an operating day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

1.59 Other Supplier

Other Supplier shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the PJM Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

1.60 Partial Requirements Service

Partial Requirements Service shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.61 Percentage Internal Resources Required

Percentage Internal Resources Required shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

1.62 Party

Party shall mean an entity bound by the terms of this Agreement.

1.63 PJM

PJM shall mean the PJM Board and the Office of the Interconnection.

1.64 PJM Board

PJM Board shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Operating Agreement.

1.65 PJM Manuals

PJM Manuals shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

1.66 PJM Open Access Transmission Tariff or PJM Tariff

PJM Open Access Transmission Tariff or PJM Tariff shall mean the tariff for transmission service within the PJM Region, as in effect from time to time, including any schedules, appendices, or exhibits attached thereto.

1.67 PJM Region

PJM Region shall have the same meaning as provided in the Operating Agreement.

1.68 PJM Region Installed Reserve Margin

PJM Region Installed Reserve Margin shall mean the percent installed reserve margin for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.69 Planned Demand Resource

Planned Demand Resource shall mean a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Schedule 6.

1.69A Planned External Generation Capacity Resource

Planned External Generation Capacity Resource shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Reliability Pricing Model Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has executed an interconnection agreement (functionally equivalent to a System Impact Study Agreement under the PJM Tariff for Base Residual Auction and an Interconnection Service Agreement under the PJM Tariff for Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and if applicable the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. An External Generation Capacity Resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

1.70 Planned Generation Capacity Resource

Planned Generation Capacity Resource shall mean a Generation Capacity Resource participating in the generation interconnection process under Part IV, Subpart A of the PJM Tariff, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Plan; (ii) a System Impact Study Agreement has been executed prior to the Base Residual Auction for such Delivery Year; (iii) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate; and (iv) no megawatts of capacity have cleared an RPM Auction for any prior Delivery Year. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

1.71 Planning Period

Planning Period shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

1.72 Public Power Entity

Public Power Entity shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

1.73 Qualifying Transmission Upgrades

Qualifying Transmission Upgrades shall have the meaning specified in Attachment DD to the PJM Tariff.

1.74 Markets and Reliability Committee

Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.75 Reliability Principles and Standards

Reliability Principles and Standards shall mean the principles and standards established by NERC or an Applicable Regional Reliability Council to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

1.76 Required Approvals

Required Approvals shall mean all of the approvals required for this Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of this Agreement.

1.77 Self-Supply

Self Supply shall have the meaning provided in Attachment DD to the PJM Tariff.

1.78 Single-Customer LSE

Single-Customer LSE shall mean a Party that (a) serves only retail customers that are Affiliates of such Party; (b) owns or controls generation facilities located at one or more of the retail customer location(s) that in the aggregate satisfy at least 50% of such Party's Unforced Capacity obligations; and (c) serves retail customers having (i) an Obligation Peak Load at all locations of no less than 100 MW, where such peak load of each such location is no less than 10 MW; or (ii) an Obligation Peak Load at each location served of no less than 25 MW.

1.79 South RAA

South RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM South Region, on file with FERC as PJM Rate Schedule FERC No. 40.

1.80 State Consumer Advocate

State Consumer Advocate shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.81 State Regulatory Structural Change

State Regulatory Structural Change shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or

(b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

1.82 Threshold Quantity

Threshold Quantity shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Schedule 8.1).

1.83 Transmission Facilities

Transmission Facilities shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

1.84 Transmission Owner

Transmission Owner shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.85 Transmission Owners Agreement

Transmission Owners Agreement shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005 and as amended from time to time, among transmission owners within the PJM Region.

1.86 Unforced Capacity

Unforced Capacity shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

1.87 West RAA

West RAA shall mean the "PJM West Reliability Assurance Agreement among the Load Serving Entities in the PJM West Region," on file with FERC as PJM Rate Schedule FERC No. 32.

1.88 Zonal Capacity Price

Zonal Capacity Price shall mean the price of Unforced Capacity in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year as determined pursuant to Attachment DD to the PJM Tariff.

1.89 Zone

Zone shall mean an area within the PJM Region, as set forth in Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load (as defined in the PJM Tariff) located outside the PJM Region that is served from such Zone under Schedule H-A of the PJM Tariff.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES, ILR, AND ENERGY EFFICIENCY

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

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

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

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

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

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

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

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

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

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Demand Resource Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the

location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

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

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

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

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

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

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

Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of Demand Resource and ILR above, there can be two notification periods:

Step 1 (Short Lead Time) – Demand Resource or ILR which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.

Step 2 (Long Lead Time) – Demand Resource or ILR which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

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

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- supplemental status reports, detailing Demand Resources and ILR available, as requested by PJM;
- Entry of customer-specific Demand Resource and ILR credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource or ILR event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource or ILR events, prepared in accordance with the PJM Manuals.

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

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource or ILR load

reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

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

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

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

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

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

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

L. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource and ILR events. The process establishes potential under/over compliance values for the Provider. Compliance will be established for each Provider on an event specific basis for the Provider's Demand Resources or ILR dispatched by the Office of the Interconnection during such event.

PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period. Compliance for Direct Load Control programs will consider only the transmission of the control signal. Providers are required to report the time period (during the Demand Resource and ILR event) that the control signal was actually sent. Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance is checked on an individual customer basis for GLD, by comparing actual load dropped during the event to the nominated amount of load drop. Providers must submit actual loads and comparison loads for the compliance hours. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

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

M. Energy Efficiency Resources

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

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of

affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value, which shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday. The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

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

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

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

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

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

SCHEDULE 8.1

FIXED RESOURCE REQUIREMENT ALTERNATIVE