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November 19, 2026

VIA E-TARIFF

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: Proposed Tariff Amendments in Response to Order No. 1920
LTRTP Cost Allocation Requirements
Docket No. ER27-575-000

Dear Secretary Reese:

Pursuant to section 205 of the Federal Power Act ("FPA"), the PJM Transmission Owners ("Transmission Owners"),[1] acting through the PJM Consolidated Transmission Owners Agreement ("CTOA"),[2] submit amendments to the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("PJM Tariff") to comply with the requirements of the Federal Energy Regulatory Commission's ("Commission's") Order No. 1920.[3] Specifically, the

[1] Pursuant to Order No. 714, this filing is submitted by PJM Interconnection, L.L.C. on behalf of the Transmission Owners as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, the Transmission Owners have requested PJM submit these amendments in the eTariff system as part of PJM's electronic Intra PJM Tariff.

[2] PJM Interconnection, L.L.C., CTOA, Rate Schedule FERC No. 42 (June 19, 2008). This filing has been authorized pursuant to the individual and weighted voting requirements in Section 8.5 of the CTOA. In addition, pursuant to CTOA, section 7.3.2 and PJM Tariff, section 9.1(b), the PJM Transmission Owners consulted with PJM and with members of the PJM Members Committee and other stakeholders by providing notice of the PJM Tariff modifications proposed in this filing, together with a draft of those modifications, on April 24, 2026 and inviting the submission of written comments by May 29, 2026.

[3] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024) ("Order No. 1920," the "Order," or the "Final Rule"), *order on reh'g*, Order 1920-A, 189 FERC ¶ 61,126 (2024) ("Order No. 1920-A"), *order on reh'g and clarification*, Order 1920-B, 191 FERC ¶ 61,026 (2025) ("Order No. 1920-B").

Transmission Owners submit these changes to comply with the requirement to develop a cost allocation methodology for Long-Term Regional Transmission Planning ("LTRTP") projects.[4] These cost allocation requirements fall within the section 205 FPA filing rights of the Transmission Owners.[5]

The Transmission Owners request that the Commission accept the proposed amendments to the PJM Tariff and find that they are just and reasonable and satisfy Order No. 1920's cost allocation requirements without hearing, modification, or condition. The Transmission Owners also request that the Commission find that the Transmission Owners complied with the requirements of Order No. 1920 as discussed herein. The Transmission Owners request that the Commission allow the proposed changes to become effective on the same effective date that the Commission accepts the compliance filings submitted by PJM and the Transmission Owners regarding proposed changes to the planning process requirements of Order No. 1920 as well as the proposed changes filed by PJM and the Transmission Owners on December 12, 2025.[6] Finally, the Transmission Owners ask that the Commission set the date for comments in response to this filing to be February 17, 2027.[7]

Under Order No. 1920-A, the Transmission Owners are required to attach to this filing the proposal of the Relevant State Entities in PJM (known as the PJM Area Relevant State Entities Committee or the "PARSEC").[8] The Transmission Owners object to this requirement as a violation of their FPA section 205 filing and First Amendment rights. The Transmission Owners' appeal of the Commission's imposition of this requirement is currently being considered by the United States Court of Appeals for the 4th Circuit.[9] Accordingly, the Transmission Owners' attachment of the PARSEC proposal to this filing is done under protest and without waiver of their constitutional and statutory rights. Moreover, it is the position of the Transmission Owners that under the FPA and Commission precedent, the Commission must accept the submission of the Transmission Owners if it concludes that it is just and reasonable

[4] Order No. 1920 at PP 1677-1685; Order No. 1920-A at PP 610-798.

[5] CTOA, § 7.3; PJM Tariff, § 9.1.

[6] *PJM Interconnection, L.L.C.*, PJM Transmission Owners, Proposed Tariff Amendments in Response to Order No. 1920 LTRTP Requirements, Docket No. ER26-744 (Dec. 12, 2025) ("TO December Compliance Filing"). To accomplish this, the Transmission Owners have entered a placeholder effective date of 12/31/9998. Once the Commission issues an order on this filing, the Transmission Owners will submit a clean-up filing to enter the actual effective date and to match PJM's actual effective date for the LTRTP Protocol.

[7] The Transmission Owners note that there is a pending request for an extension filed by the Public Interest Organizations requesting that the comment date be extended to February 17, 2027. In that filing, the Public Interest Organizations state that the Transmission Owners, along with PARSEC and PJM agreed to an extension to January 21, 2027. Having further evaluated the request, the Transmission Owners agree to the further extension until February 17, 2027, as requested in the motion.

[8] Order No. 1920-A at P 651.

[9] *Appalachian Voices, et al. v. FERC*, Docket No. 24-1650 (4th Cir. Jul. 16, 2024).

without first considering any alternate proposal put forward by the PARSEC or any other entity.[10]

[10] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Request for Rehearing of Order No. 1920-A of the Indicated PJM Transmission Owners, Section III(D), Docket No. RM21-17-003 (Dec. 23, 2024).

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I. INTRODUCTION

Order No. 1920 places two general compliance requirements on the Transmission Owners regarding cost allocation. First, the Transmission Owners must engage with the Relevant State Entities in their region for purposes of developing a cost allocation methodology for PJM's LTRTP projects.[11] Second, the Transmission Owners must develop and file a just and reasonable *ex ante* cost allocation methodology for those projects.[12] The Transmission Owners have met both requirements.

The Transmission Owners engaged with the PARSEC over a nearly two-year long period that included education, cooperation, negotiation, and compromise between the two groups. The engagement period also included several months of negotiations with the assistance of the Commission's Dispute Resolution Service ("DRS") in an effort to develop a consensus cost allocation proposal.[13] While the Transmission Owners and the PARSEC could not reach agreement, the Transmission Owners made every effort to reach consensus, including prioritizing and adopting elements that they understood were consistent with the states' objectives, when they were legally durable and did not undermine PJM's ability to ensure that necessary transmission projects are planned and developed.

The Transmission Owners also propose an ex ante cost allocation methodology that complies with Order No. 1920. The Transmission Owners' proposal adds a new section to Schedule 12 of the PJM Tariff to allocate costs for LTRTP Projects. The proposal seeks to apply existing, Commission-approved cost allocation methodologies already in use in PJM to LTRTP projects and tailors them to the structure of PJM's proposed Long-Term Regional Transmission Planning Protocol ("LTRTP Protocol"). The result is a just and reasonable proposal with a cost allocation methodology that fully complies with the principles of cost causation and the requirements of Order No. 1920, that is consistent with PJM's LTRTP process and can be efficiently implemented by PJM upon Commission approval.

A. Robust and Sincere Engagement with the PARSEC Resulted in the Transmission Owners' Adopting Several State Priorities

The Transmission Owners conducted a robust and sincere engagement with the PARSEC. The Transmission Owners facilitated an Engagement Period designed to promote meaningful dialogue, provided notice consistent with Order No. 1920's requirements, and, in coordination

[11] Order No. 1920 at P 1354.

[12] *Id.* P 1403.

[13] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Notice of Extension of Time, Docket No. RM21-17 (June 11, 2026) ("June 11, 2026 Notice of Extension of Time"); *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Notice of Extension of Time, Docket No. RM21-17 (Aug. 11, 2026) ("August 11, 2026 Notice of Extension of Time"); *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Notice of Extension of Time, Docket No. RM21-17-000 (Sept. 15, 2026) ("September 15, 2026 Notice of Extension of Time").

with Organization of PJM States, Inc. ("OPSI") leadership, established a robust mailing list for distribution of materials and meeting invitations to ensure all relevant parties were able to participate.

In light of the Order's requirement to provide a forum enabling meaningful participation, the Transmission Owners organized and hosted a series of meetings throughout what ultimately became an almost two-year long Engagement Period that included over four months of extensive negotiations with the assistance of Commission DRS Staff. In total, the Transmission Owners and PARSEC convened 14 formal meetings during the initial 18-month Engagement Period (prior to DRS discussions), each designed to encourage active participation, questions, and feedback from state representatives. In addition, the Transmission Owners and PARSEC participated in numerous meetings and other communications through their leadership and counsel. The early portion of this engagement included educational sessions on just and reasonable cost allocation methodologies, with the goal of establishing a common foundation for informed negotiations. As discussions progressed, the Transmission Owners facilitated ongoing dialogue and responded to PARSEC's interests and requests. Indeed, by the time Order No. 1920-A imposed an explicit obligation on Transmission Owners to participate in cost allocation discussions upon request, the Transmission Owners and PARSEC were already deeply engaged in such discussions.

The Transmission Owners worked collaboratively with PARSEC to extend the Engagement Period twice, with Commission approval, to allow additional time for negotiation and alignment. In June, the PJM Transmission Owners and the PARSEC also asked the Commission to extend the deadline for compliance in this proceeding and engaged with DRS Staff in a further attempt to reach resolution. Throughout the engagement with the PARSEC, the Transmission Owners made good-faith efforts to reach consensus. The goal of the Transmission Owners has been and continues to be to develop a cost allocation that addresses the goals and concerns articulated by the PARSEC, is consistent with applicable legal principles, can be implemented efficiently by PJM, is transparent, does not risk imposing unnecessary costs on customers, will foster the development of necessary transmission and meets the goal in Order No. 1920. The goal in Order No. 1920 is to identify transmission necessary to address the long-term needs of the PJM region and any cost allocation methodology filed in compliance should support that goal and should not be an impediment to such transmission projects being built.

Ultimately, the Transmission Owners and the PARSEC could not reach agreement on a single proposal but, as discussed in more detail below, the Transmission Owners have tailored components of their cost allocation proposal to reflect concepts that the Transmission Owners understood the PARSEC supported. While the parties were unable to reach resolution, the Transmission Owners appreciate PARSEC's efforts and constructive dialogue, which helped the Transmission Owners understand the objectives of the states as detailed in Section II.E, *infra*. The Transmission Owners remain open to engaging with PARSEC in the future.

B. Cost Allocation Proposal Parallels Commission-Approved PJM Frameworks

The proposal builds directly on existing PJM cost allocation frameworks—hybrid allocation, use of Load Ratio Share ("LRS") and Solution-Based Distribution Factor

("SBDFAX") analyses, and a voluntary state agreement mechanism—that the Commission has previously found to be just and reasonable. Specifically, the PJM Transmission Owners propose the following:[14]

- **Regional and Necessary Lower Voltage LTRTP projects**. A proposed hybrid methodology that builds on the existing LRS and SBDFAX hybrid cost allocation used for regional RTEP projects. Specifically, the Transmission Owners propose to use SBDFAX and LRS to allocate the cost for Regional and Necessary Lower Voltage LTRTP projects but to adopt different percentages for Core Needs projects and Additional Needs projects that reflect the unique nature of these two categories of projects. For Core Needs projects, the Transmission Owners adopt a 50% and 50% LRS-SBDFAX allocation, consistent with the ratio the Commission approved—and the D.C. Circuit upheld—for RTEP Regional Facilities.[15] This ratio reflects that Core Needs projects, like reliability projects, provide equivalent amounts of widespread regional benefits and identifiable usage-based benefits over time. For Additional Needs projects, the Transmission Owners' proposal includes a more SBDFAX-weighted allocation (85% SBDFAX and 15% LRS), recognizing that these projects are more closely tied to state-driven policy and economic objectives and therefore produce more targeted benefits. The decision to use a different methodology for Core and Additional Needs projects reflects a common understanding with the states that costs aligned with the nature and distribution of Additional Needs project benefits differ from those of Core Needs projects while remaining within the range of reasonable ratemaking judgments recognized by the Commission.

- **Lower Voltage Projects.** The costs of Lower Voltage Facilities addressing Core Needs and Additional Needs included in the LTRTP will be allocated using 100% SBDFAX. Facilities with a planning cost under $5 million will continue to be assigned to the host zone consistent with current provisions of Schedule 12.

- **Voluntary Funding Process.** A proposed process that allows entities, including PARSEC, to submit a Voluntary Funding Agreement for Required Transmission Enhancements to be included in the All-in-One Plan. The agreement will be submitted to the Transmission Owners Agreement Administrative Committee ("TOAAC") for consideration and filing, consistent with TOAAC voting protocols to make section 205 filings.

- **State Agreement Process.** A proposed process by which the PARSEC can propose and submit to the TOAAC a State Cost Assignment Agreement within six months after LTRTP approval that would provide an alternative methodology for allocating the costs of specific projects addressing Core or Additional Needs. The agreement

[14] Unless addressed in the proposed Tariff amendments, other provisions of Schedule 12 will continue to apply as applicable.

[15] PJM Tariff, Sch. 12, § (b)(i)(A); *Long Island Power Auth. v. FERC*, 27 F.4th 705, 713-14 (D.C. Cir. 2022).

will be submitted to the TOAAC for consideration and filing, consistent with TOAAC voting protocols to make section 205 filings. The proposal process builds on the same core structure as the existing Commission-approved State Agreement Approach in PJM but is adapted to the framework of PJM's proposed LTRTP process. While the Transmission Owners initially had concerns regarding adopting a State Agreement Process for Core Needs projects, they ultimately expanded their proposal to address both Core Needs and Additional Needs to provide the states with greater flexibility and input in the cost allocation of specific projects, consistent with Order No. 1920.

- **Assignment of Costs to Individual States.** A process that will allow costs to be allocated to individual states within a transmission owner zone covering multiple states if it is necessary to accommodate a State Cost Assignment Agreement or Voluntary Funding Agreement proposal.

- **Consultation on Future Amendments.** A set of procedures to provide a process to consult with the Relevant State Entities on post-compliance amendments to the 1920 cost allocation methodology within defined 30-day timeframes, to post the results of the consultation on the PJM Website, and to preserve section 206 filing rights for PJM and the PARSEC.

C. The Transmission Owners Propose A Just and Reasonable Cost Allocation That Fully Complies With the Requirements of Order No. 1920

The Transmission Owners' LTRTP cost allocation methodology is just and reasonable and compliant with the requirements of Order No. 1920. The proposal is firmly grounded in cost allocation constructs the Commission has already approved, and the D.C. Circuit has upheld, for the PJM region specifically.[16] Those constructs were designed for the dynamics of PJM's multi-state, multi-zone system and are well suited to LTRTP projects. The proposal carefully applies those constructs to the distinct characteristics of long-term planning projects. As a result, the methodology ensures that costs will be allocated in a manner that is at least roughly commensurate with benefits, consistent with Commission and judicial precedent.[17] Importantly, because the Transmission Owners' proposal is that LTRTP Core Needs projects will use the same 50% LRS and 50% SBDFAX ratio as Order No. 1000 regional projects, this proposal removes any incentive to game the system by steering projects between planning processes in the hopes of obtaining a preferred cost allocation.

By applying existing constructs to develop a LTRTP cost allocation methodology, the Transmission Owners have ensured that their proposal complies with the cost allocation principles incorporated into Order No. 1920. The hybrid methodologies for both Core and Additional Needs projects satisfy Cost Allocation Principles 1 through 5. Importantly, the

[16] *Long Island Power Auth. v. FERC*, 27 F.4th 705, at 713-14 (D.C. Cir. 2022).

[17] *Id.*

methodology does not impermissibly allocate costs based on project type but rather distinguishes between categories of system needs to better align cost responsibility with benefits.

Finally, the Transmission Owners' proposal incorporates an enhanced State Agreement Process that gives the Relevant State Entities the opportunity to be active participants in shaping how the costs of both Core Needs and Additional Needs projects are allocated. By including a robust State Agreement Process that includes both project types, the Transmission Owners' proposal gives states substantial freedom to determine how costs are allocated for LTRTP projects.

In sum, the Transmission Owners have advanced a comprehensive, precedent-based, and just and reasonable approach that satisfies Order No. 1920's requirements.

II. BACKGROUND

A. Procedural History

Order No. 1920 requires transmission providers to "conduct Long-Term Regional Planning that will ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs."[18] In PJM, the Transmission Owners have transferred their section 205 rights regarding regional transmission planning to PJM and retained those rights regarding cost allocation. Thus, for the purpose of Order No. 1920, PJM is responsible for compliance with the LTRTP planning requirements and the Transmission Owners are responsible for compliance with the LTRTP cost allocation requirements.

The Final Rule ordered compliance filings to be submitted "within ten months of the effective date of this final rule revising its [Tariff] and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets all of the requirements adopted in this final rule."[19] The Commission has extended this deadline several times, recognizing the need for additional time to continue discussions as part of the Engagement Period between the Transmission Owners and the PARSEC to develop the cost allocation proposal to satisfy Order No. 1920. On February 6, 2025, the Commission granted the Transmission Owners' request, made jointly with the PARSEC, to extend the Engagement Period until October 7, 2025, and to extend the Transmission Owners' compliance filing deadline to December 12, 2025. On October 17, 2025, the Commission further extended the Transmission Owners' compliance filing deadline with respect to cost allocation in the PJM region to June 12, 2026.[20]

[18] Order No. 1920, Summary.

[19] *Id.* P 12.

[20] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Notice of Extension of Time, Docket No. RM21-17, at 3 (Oct. 17, 2025).

On December 12, 2025, the Transmission Owners submitted an amendment to Attachment M-3 and a new Attachment M-5 of the PJM Tariff to comply with Order No. 1920's requirements regarding the transparency of local transmission planning and the coordination of regional and local transmission planning processes, which fall under the Transmission Owners' section 205 rights with regard to local planning.[21] The same day, PJM filed its proposed LTRTP Protocol.[22]

The Commission then granted two additional extensions of the Engagement Period and the cost allocation compliance deadline.[23] At the request of the PJM Transmission Owners and PARSEC, the Commission also made its DRS available to the Transmission Owners and PARSEC.[24] As indicated in the notice issued by Director of DRS on July 10, 2026 and described in their Motions for Extension of Time filed on August 4 and September 8, 2026, the Transmission Owners and PARSEC engaged DRS services to work towards a consensus proposal satisfactory to all.[25] In the September 15, 2026 Notice of Extension of Time, the Commission approved a further extension of the Engagement Period for the Transmission Owners to continue discussions with the PARSEC, indicating that the Transmission Owners would file a motion to govern that would establish a schedule for submission of the compliance filing.[26] Ultimately, the parties could not reach agreement, and the Transmission Owners, the PARSEC and PJM filed a Motion to Govern on September 25, 2026. This motion was granted by the Commission on October 8, 2026, setting the compliance filing deadline for November 19, 2026, for the Transmission Owners and December 22, 2026 for PJM.[27]

[21] TO December Compliance Filing.

[22] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Compliance Filing of PJM Interconnection, L.L.C. and Request for Extension of Comment Period, Docket No. ER26-751 (Dec. 12, 2025) ("PJM December Compliance Filing").

[23] June 11, 2026 Notice of Extension of Time; August 11, 2026 Notice of Extension of Time.

[24] June 11, 2026 Notice of Extension of Time, at 2-3.

[25] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Dispute Resolution Service Status Report, Docket No. RM21-17 (July 10, 2026); *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Unopposed Joint Motion for Extension of Time, Docket No. RM21-17 (Aug. 4, 2026); *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Unopposed Joint Motion for Extension of Time to File Motions to Govern, Docket No. RM21-17 (Sept. 8, 2026).

[26] September 15, 2026 Notice of Extension of Time, at 2-3.

[27] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Unopposed Joint Motions to Govern Future Proceedings, Docket No. RM21-17-000 (Sept. 25, 2026) ("September 25, 2026 Unopposed Joint Motions to Govern Future Proceedings"); *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Notice Granting Motion to Govern Further Proceedings, Docket No. RM21-17-000, at 2 (Oct. 8, 2026).

B. PJM's Proposed Long-Term Regional Transmission Planning Protocol

PJM's LTRTP protocol provides for a 20-year planning horizon using five-year planning cycles.[28] Under its proposal, PJM will first develop at least three plausible and diverse Long-Term Scenarios, each based on best available data inputs and factors within the seven Factor Categories (as defined by the Final Rule) that are likely to affect Long-Term Transmission Needs.[29] Based on these Long-Term Scenarios, PJM will identify a comprehensive list of Long-Term Transmission Needs in the PJM Region.[30] It will identify these needs as either Core Needs or Additional Needs through consultation with the states and stakeholders.[31] This distinction between Core Needs and Additional Needs is also fundamental to the cost allocation framework that the Transmission Owners are proposing in this filing. While these are distinct categories, they do not squarely break down into "project types" like reliability, economic, and public policy projects contemplated by Order No. 1000. Rather:

- Core Needs are needs associated with maintaining system reliability as determined by the following model inputs: projected transmission system topology; forecasted future demand, including load growth and firm transmission commitments; projected generation resource deactivations and additions; and a generation resource mix capable of meeting applicable reliability criteria.[32] Core Needs thus *must be addressed to ensure reliability and other system needs*;[33] and

- Additional Needs are those needs that are more influenced by the additional drivers *which could be different or go beyond those needed to support system reliability.*[34]

Following the identification of Core and Additional Needs, PJM will conduct a competitive solicitation window under its Order No. 1000-compliance sponsorship model, similar to its existing RTEP Protocol process.[35] PJM will then, through a two-step process, develop an "All-in-One Plan" of Long-Term Transmission Projects, including proposals submitted through the competitive windows, to maximize benefits to customers relative to costs.[36] As the first step, PJM will develop a Core Plan that addresses Core Needs, applying a 1.0 benefit to cost ratio threshold on a portfolio basis.[37] Next, PJM will develop the All-in-One

[28] PJM December Compliance Filing at 7 (footnote omitted).

[29] *Id.* (footnotes omitted).

[30] *Id.* at 8 (footnote omitted).

[31] *Id.* at 10-12, 69 (footnotes omitted).

[32] *Id.* at 69 (citation omitted).

[33] *Id.* (emphasis added).

[34] *Id.* (emphasis added) (citation omitted).

[35] PJM December Compliance Filing, at 8, 32-33 (citations omitted).

[36] *Id.* at 9-11 (footnotes omitted).

[37] *Id.* at 11.

Plan that addresses both Core Needs and Additional Needs holistically and combined.[38] For projects or the portion of projects addressing Additional Needs, PJM will apply a 1.25:1 benefit to cost ratio.[39] States and third parties also have the opportunity to voluntarily fund any proposal that is not selected in the All-in-One Plan pursuant to a Voluntary Funding Agreement, and such voluntarily funded projects will be included in the final plan.[40] Then, the LTRTP is finalized, comprising a plan of voluntary funded solutions and transmission solutions that holistically address Core and Additional Needs and incorporated into PJM RTEP and ultimately approved by the PJM Board.[41]

C. Relevant Aspects of the Approved Cost Allocation Methodology in PJM Tariff for Order No. 1000 RTEP Projects

At present, under Schedule 12 of the PJM Tariff, costs are allocated on a region-wide basis for Required Transmission Enhancements included in PJM's RTEP. Broadly, Schedule 12 uses two methodologies to allocate these costs for RTEP Reliability Projects.[42] For Regional Facilities and Necessary Lower Voltage Facilities,[43] 50% of costs are assigned annually using LRS.[44] LRS is a postage-stamp cost allocation methodology that allocates costs broadly across the PJM region based on each transmission zone's annual peak load as a proportional share of the sum of all zonal peak loads in PJM.[45] The remaining 50% of costs are assigned using the SBDFAX analysis.[46] SBDFAX allocates costs using a flow-based methodology that assigns costs based on a zone's use of and reliance on a particular reliability project. It is updated

[38] *Id.* at 9-11 (footnotes omitted). The All-in-One Plan may include projects exclusively addressing Core Needs or Additional Needs, respectively, or projects that address both. The latter may modify or completely replace projects in the Core Plan.

[39] *Id.*

[40] *Id.*

[41] *Id.* at 11, 25-27 (footnotes omitted).

[42] *See* PJM Tariff, Sch. 12, § (b)(i)(A)(2)(a) (A Reliability Project is "a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to address one or more reliability violations or to address operational adequacy and performance issues.").

[43] Regional Facilities are facilities that go into a double-circuit 345 kV or higher Required Transmission Enhancement. Necessary Lower Voltage Facilities are facilities that operate below 345 kV that do not otherwise meet the criteria to be a Required Transmission Enhancement but that must be constructed or strengthened to support new Regional Facilities. PJM Tariff, Sch. 12 § (b)(i).

[44] *Id.* § (b)(i)(A)(1).

[45] *Id.* § (b)(i)(A)(2)(a).

[46] *Id.* § (b)(i)(A)(1)(a).

annually once the project is in service.[47] The costs of Lower Voltage Reliability Facilities[48] in the RTEP are assigned solely using the SBDFAX analysis.[49]

At present, the PJM Tariff contains a State Agreement Approach as a supplementary transmission planning and cost allocation mechanism for State Agreement Public Policy Projects.[50] A State Agreement Public Policy Project is a transmission enhancement or expansion proposed pursuant to Operating Agreement, Schedule 6, section 1.5.9(a) which is not a Supplemental Project (*i.e.*, a transmission project that is constructed by a Transmission Owner pursuant to a public policy requirement and not included in the RTEP as a Required Transmission Enhancement). Pursuant to Schedule 12, section (b)(xii), if a State Agreement Public Policy Project is proposed, the Transmission Provider (*i.e.*, PJM Office of Interconnection) shall submit a proposed cost assignment for the project to the TOAAC for consideration and filing pursuant to CTOA, section 7.3 and PJM Tariff, Part I, section 9.1(a). If the TOAAC declines to make the filing, section (b)(xii) provides that PJM or the state governmental entities proposing such project can file the proposed cost allocation pursuant to section 206 of the FPA.

D. Order No. 1920's Requirements for LTRTP Cost Allocation

Order No. 1920 requires transmission providers to file one or more *ex ante* cost allocation methodologies that apply to selected Long-Term Regional Transmission Facilities.[51] An *ex ante* cost allocation method sets a predetermined default method for distributing costs roughly commensurate with benefits.[52] The Order determined that these Long-Term Regional Transmission Cost Allocation Methods must comply with five of the six existing regional cost allocation principles set out in Order No. 1000:

> (1) the costs of selected transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits;
>
> (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities;
>
> (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1;

[47] *Id.* § (b)(iii).

[48] Lower Voltage Facilities are Required Transmission Enhancements that are not Regional Facilities and are not Necessary Lower Voltage Facilities. *Id.* § (b)(ii).

[49] *Id.*

[50] PJM Tariff, Sch. 12, section (b)(xii); *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024, at P 2 (2022).

[51] Order No. 1920 at P 1291.

[52] *Id.* PP 1291-92, 1305.

> (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; and
>
> (5) the method for determining benefits and identifying beneficiaries must be transparent.[53]

The Commission found that these principles remained relevant for Order No. 1920 *ex ante* cost allocation methodologies.[54] But, in rejecting Order No. 1000's sixth regional cost allocation principle, the Commission determined that transmission providers may not adopt different Long-Term Regional Transmission Cost Allocation Methods for different project types.[55]

The Order established a six-month Engagement Period during which transmission providers and Relevant State Entities could work toward an agreement concerning an *ex ante* cost allocation method.[56] Order No. 1920-A also requires, if the Relevant State Entities so request that an alternative cost allocation methodology developed by the Relevant State Entities be attached to the Transmission Owners' compliance filing.[57] Order No. 1920-A further clarifies that transmission providers also must consult with Relevant State Entities before amending the cost allocation methods.[58]

E. Robust Engagement Period with PARSEC

As required by Order No. 1920, the Transmission Owners facilitated a robust and lengthy Engagement Period with the Relevant State Entities in the PJM region, who organized themselves as the PARSEC. The Engagement Period lasted just shy of 24 months, beginning on October 7, 2024, and concluding on September 25, 2026, upon the filing of the Motion to Govern. The start of the Engagement Period was noticed via a post on the PJM website.[59] As required by Order No. 1920, the Notice also included contact information for entities interested in participating in the Engagement Period and included a deadline for the Engagement Period to end and the Relevant State Entities to provide a proposal to the Transmission Owners.[60] The

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[53] *Id.* P 1471 (citations omitted).

[54] *Id.* P 1472.

[55] *Id.* P 1474.

[56] *Id.* P 1354.

[57] Order No. 1920-A at PP 12, 13, 16. The Transmission Owners object to these latter two "Consultation" requirements as violating their rights under the FPA and First Amendment to the Constitution. This objection is also currently being considered by the United States Court of Appeals for the 4th Circuit. *See supra*, n. 9.

[58] Order No. 1920-A at P 691.

[59] Attachment C, Declaration of Amber Thomas at ¶¶ 6, 8, 9, 12, 19, 22 ("Thomas Decl.").

[60] *Id.* ¶ 9; PJM, Transmission Expansion Advisory Committee, https://www.pjm.com/committees-and-groups/committees/teac.

Transmission Owners, working with their state representatives, also developed a comprehensive service list that was used for meeting invitations and information distribution so that interested parties were kept up to date on developments.[61]

The Transmission Owners and the PARSEC formally met 14 times during the initial Engagement Period prior to engaging in the DRS process.[62] PJM also typically joined these meetings. In between these formal meetings, Transmission Owner members, PARSEC members, Transmission Owners' counsel, and PARSEC leadership had numerous informal conversations and written exchanges.

For the first few months of the Engagement Period, from fall 2024 to spring 2025, the meetings focused on providing education to the PARSEC about various just and reasonable cost allocation methodologies in use in PJM and elsewhere and the various milestone legal precedents that have addressed regional cost allocation.

Over the summer and early fall of 2025, the Engagement Period meetings also focused on PJM's development of a LTRTP Protocol proposal and its impact on cost allocation. Any cost allocation methodology would need to work within PJM's LTRTP Protocol framework. The parties used these meetings to develop their understanding of PJM's planning proposal and its potential impacts on a cost allocation proposal.

From fall 2025 to spring 2026, the Transmission Owners worked to finalize the details of the cost allocation proposal that could be presented to the PARSEC for consideration. During that period, the Transmission Owners understood that the PARSEC also was developing its own cost allocation proposal. The Transmission Owners' goal throughout the Engagement Period was to reach agreement on a cost allocation proposal with the PARSEC and to work with PARSEC to develop a legally sound methodology that met the requirements of Order No. 1920 and could be properly implemented in PJM. Accordingly, the Transmission Owners developed their proposal informed by the feedback from their discussions with PARSEC and its members including: (1) a hybrid SBDFAX and LRS methodology for regional projects; (2) separate weighting of SBDFAX for Core Needs Projects and Additional Needs Projects; (3) the structure of the State Agreement Process; and (4) a method to identify state-specific benefits within a multi-state zone to facilitate a State Agreement Process or voluntary funding process.

On March 16 and March 30, 2026, the Transmission Owners held formal meetings with the PARSEC to present their cost allocation proposal and to discuss the proposals that the PARSEC was considering.[63] These meetings provided opportunity for the Transmission Owners and PARSEC to ask questions about the respective proposals.[64] After the meeting on March 30, 2026, the Transmission Owners and PARSEC agreed to extend the Engagement Period to April

[61] Thomas Decl. ¶¶ 6-7.

[62] *Id.* ¶ 8.

[63] *Id.* ¶¶ 8, 13.

[64] *Id.* ¶ 13.

14, 2026, to allow discussions to continue. On April 14, 2026, the PARSEC sent the Transmission Owners a formal proposal adopted pursuant to the PARSEC voting protocol and asked the Transmission Owners to include the proposal as an attachment to the June 12, 2026 compliance filing.[65]

On June 4, 2026, the Transmission Owners and PARSEC agreed to continue discussions in an attempt to reach resolution and jointly sought an extension of time and requested that the Commission make its DRS resources available to them.[66] On June 11, 2026, the Commission granted an extension of the Engagement Period and the cost allocation compliance deadline and made the DRS available to the Transmission Owners and PARSEC.[67] The two parties engaged those services for several months during which they had several meetings with the assistance of DRS Staff. On September 15, 2026, the Commission approved a further extension of the Engagement Period for the Transmission Owners to continue discussions with the PARSEC.[68] The Transmission Owners, the PARSEC and PJM filed a Motion to Govern on September 25, 2026, reporting that the Transmission Owners and PARSEC had not reached agreement.[69] The Motion to Govern was granted by the Commission on October 8, 2026, setting the Transmission Owners' compliance filing deadline for November 19, 2026.[70] No further meetings between the Transmission Owners and PARSEC were held, and the Engagement Period formally ended upon the filing of the Motion to Govern. Accordingly, as Order No. 1920-A requires,[71] the PARSEC's alternative methodology is attached to this filing.[72]

[65] *Id.* ¶¶ 14, 16.

[66] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Joint Motion for Extension of Time, Docket No. RM21-17 (June 4, 2026).

[67] June 11, 2026 Notice of Extension of Time, at 2-3; August 11, 2026 Notice of Extension of Time, at 2.

[68] September 15, 2026 Notice of Extension of Time, at 2.

[69] September 25, 2026 Unopposed Joint Motions to Govern Future Proceedings.

[70] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Notice Granting Motion to Govern Further Proceedings, Docket No. RM21-17-000, at 2 (Oct. 8, 2026). The motion requested and the Commission granted PJM with a further extension to December 22, 2026 to file any related or revised provisions to its Long Term Regional Transmission Planning Protocol needed to reflect the proposals submitted on November 19, 2026.

[71] Order No. 1920 at PP 25-27; Order No. 1920-A at PP 12, 13.

[72] *See* Attachment D, PARSEC Materials. As noted *supra*, the Transmission Owners are complying with Order No. 1920-A by attaching PARSEC's alternative methodology under protest. This requirement constitutes compelled speech in violation of the First Amendment and violates the Transmission Owners' FPA section 205 rights.

F. Transmission Owners' Process to Develop LTRTP Cost Allocation Proposal

The tariff changes proposed in this filing reflect this coordination to ensure that the proposed cost allocation tariff provisions are compatible with the framework and timing of PJM's proposed LTRTP Protocol.[73]

After the initial engagement with PARSEC and PJM, the Transmission Owners finalized the framework and essential components of the cost allocation proposal. The TOAAC then moved forward with its obligation under the CTOA and the PJM Tariff to consult with the PJM Members Committee and other stakeholders by providing notice of the PJM Tariff modifications proposed in this filing, together with a draft of those proposed Tariff provisions, on April 24, 2026, and inviting the submission of written comments by May 29, 2026.[74] At the time, the PJM Transmission Owners anticipated voting on the Tariff changes and filing in June 2026. However, as noted above, prior to filing in June, the PJM Transmission Owners and PARSEC sought an extension of time to continue discussions with the PARSEC and sought to engage DRS services as discussed above.

After the discussions with the PARSEC ended in September, the Transmission Owners made changes to the proposal noticed to the Members Committee and Stakeholders on April 24, 2026, based on their discussions with the PARSEC during the DRS process. These changes were made in response to comments and concerns expressed by the PARSEC during the DRS process. On November 12, 2026, the TOAAC approved the proposed changes to the PJM Tariff included with this filing.

III. DESCRIPTION OF THE PROPOSED TARIFF CHANGES IMPLEMENTING THE PJM TRANSMISSION OWNERS' ORDER NO. 1920 COST ALLOCATION PROPOSAL.

The Transmission Owners propose to add a new section (b)(xix) to Schedule 12 of the PJM Tariff to govern the assignment of cost responsibility for Regional Facilities[75] and

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[73] Thomas Decl. ¶ 13.

[74] This consultation occurred pursuant to CTOA, section 7.3.2 and PJM Tariff, section 9.1(b).

[75] Regional Facilities are:

> (a)[] A.C. facilities that operate at or above 500 kV; (b) constitute a single Required Transmission Enhancement comprising two A.C. circuits operating at or above 345 kV and below 500 kV, where both circuits originate from a single substation or switching station at one end and terminate at a single substation or switching station at the other end, regardless of whether or not the two circuits are routed in the same right-of-way ("Double-circuit 345 kV Required Transmission Enhancement"); (c) are A.C. or D.C. shunt reactive resources (such as capacitors, static var compensators, static synchronous condenser (STATCON), synchronous condensers, inductors, other shunt devices, or their equivalent) connected to a Transmission Facility described in clause (a) or (b) of this subsection, or (d) are D.C. facilities meeting the criteria set forth in subsection (b)(i)(D).

PJM Tariff, Sch. 12, section (b)(i).

Necessary Lower Voltage Facilities[76] that are included in the LTRTP. Except as described below, the assignment of cost responsibility for Required Transmission Enhancements included in the LTRTP would continue to be governed by the provisions of the existing Schedule 12, section (b), as applicable.

A. Proposed Changes to Provide Cost Allocation for Regional Projects and Necessary Lower Voltage Projects.

In Schedule 12, section (b)(xix)(A)–(C), the Transmission Owners propose an *ex ante* cost allocation methodology for Regional and Necessary Lower Voltage Facilities (as defined in PJM Tariff, Schedule 12) that are included in the LTRTP that is a hybrid of LRS (as defined in PJM Tariff, Schedule 12, section (b)(i)(A)(1)(a) or (b)(i)(A)(1)(b), as applicable) and SBDFAX (as defined in PJM Tariff, Schedule 12, section (b)(iii)). The Transmission Owners propose that the ratio of costs assigned via LRS and SBDFAX vary based on whether the costs address Core Needs or Additional Needs:

- In Schedule 12, section (b)(xix)(A), the Transmission Owners propose a hybrid ratio of 50% LRS and 50% SBDFAX for Required Transmission Enhancements included in the LTRTP solely to address Core Needs.[77]

- In Schedule 12, section (b)(xix)(B), the Transmission Owners propose a hybrid ratio of 15% LRS and 85% SBDFAX for Required Transmission Enhancements included in the LTRTP to solely address Additional Needs.[78]

- In Schedule 12, section (b)(xix)(C)(1)(a), the Transmission Owners propose that, for Required Transmission Enhancements that address both Core Needs and Additional Needs, the cost of addressing the Core Needs be allocated according to a 50% LRS and 50% SBDFAX ratio, and the cost of addressing the Additional Needs be allocated according to a 15% LRS and 85% SBDFAX ratio. To determine the proportion of costs of such projects assigned, respectively to Core Needs and Additional Needs, PJM will subtract the costs of addressing only the Core Needs as determined in the

[76] Necessary Lower Voltage Facilities are:

> [N]ew A.C. Transmission Facilities or expansions or enhancements to existing Transmission Facilities that operate below 500 kV (or 345 kV in the case of a Regional Facility described in clause (1)(b) of this subsection) or new D.C. Transmission Facilities that do not meet the criteria of subsection (b)(i)(D) that must be constructed or strengthened to support new Regional Facilities, based on the planning criteria used by the Transmission Provider in developing the applicable Regional Transmission Expansion Plan.

PJM Tariff, Sch. 12, section (b)(i).

[77] Proposed Tariff, Sch. 12, section (b)(xix)(A).

[78] Proposed Tariff, Sch. 12, section (b)(xix)(B).

Core Plan from the total cost of the All-in-One project, with the former allocated as Core Needs and the remainder allocated as Additional Needs.[79]

B. Cost Allocation for Lower Voltage Projects.

In Schedule 12, section (b)(xix)(C)(2), Lower Voltage Facilities included in the LTRTP will be allocated using 100% SBDFAX.[80] However, consistent with the existing cost allocations under Schedule 12, the cost of facilities with a planning cost under $5 million will continue to be assigned to the host zone.[81] Because the Transmission Owners propose adopting the existing methodology for Lower Voltage Facilities included in the LTRTP, only minor changes are required to the Tariff to implement this proposal.[82]

C. Proposed Changes to Implement Process for Customers to Voluntarily Fund Projects.

Proposed Tariff, Schedule 12, section (b)(xix)(D) provides for a cost allocation process using a Voluntary Funding Agreement. It sets forth that if a Voluntary Funding Agreement is proposed pursuant to Operating Agreement, Schedule 6-C, section 1.14 (Voluntary Funding for Long-Term Transmission Project(s) Addressing Additional LT Needs),[83] to fund a Required Transmission Enhancement included in the All-in-One Plan (the recommended plan to be approved as the LTRTP under PJM's LTRTP proposal), such agreement will be submitted to the TOAAC for consideration and filing. Subsection (D) also provides that PJM or parties to such a Voluntary Funding Agreement are not prevented from filing their proposed cost assignment under section 206, if the Transmission Owners do not file the Voluntary Funding Agreement under section 205. If a filed Voluntary Funding Agreement cost assignment is accepted by the Commission, such cost assignment shall supersede the *ex ante* cost allocation.

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[79] Proposed Tariff, Sch. 12, section (b)(xix)(C)(1)(a).

[80] PJM Tariff, Sch. 12, section (b)(ii); Proposed Tariff, Sch. 12, section (b)(xix)(C)(1)(b). Lower Voltage Facilities are defined as any Required Transmission Enhancements that are neither Regional Facilities nor Necessary Lower Voltage Facilities.

[81] PJM Tariff, Sch. 12, section (b)(vi). The Proposed Tariff specifically includes a reference to section (b)(xix).

[82] The Commission has recently directed PJM to remove the .01 *de minimis* exclusion from the SBDFAX methodology. *See Consolidated Edison Co. of N.Y. v. PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,179 *reh'g denied*, 197 FERC ¶ 61,014 (2026). It is the intent of the Transmission Owners that this modification to the SBDFAX methodology and any future modification accepted by the Commission will apply to projects under the LTRTP process, such that SBDFAX is applied consistently in all PJM planning and cost allocation.

[83] In PJM's December 2025 filing, it reserved Schedule 6-C, section 1.14 and the Transmission Owners understand that PJM is planning on filing a supplemental compliance filing that includes a process for reaching a Voluntary Funding Agreement in section 1.14.

D. Proposed Changes to Implement a State Agreement Process.

Proposed Tariff, Schedule 12, section (b)(xix)(E) provides a process to implement the results of a State Agreement Process to assign cost responsibility for specific projects if the PARSEC adopts a State Agreement Process. Subsection (E) states that if, within six months following the approval of an LTRTP, the PARSEC proposes a State Cost Assignment Agreement pursuant to their State Agreement Process to assign such costs of a Required Transmission Enhancement and provides it to PJM, then PJM will submit such State Cost Assignment Agreement to the TOAAC for consideration and filing. Furthermore, Subsection (E) provides that it shall not prevent PJM or the PARSEC from filing a proposed assignment of costs for such Required Transmission Enhancements pursuant to section 206, if the Transmission Owners do not file the State Cost Assignment Agreement under section 205. If a filed State Cost Assignment Agreement is accepted by the Commission, the assignment of costs under such agreement shall supersede any such assignment pursuant to the *ex ante* cost allocation for LTRTP projects.

E. Proposed Changes to Implement a Formula for Assigning Costs to Individual States.

Proposed Tariff, Schedule 12, section (b)(xix)(F) provides a method for assigning cost responsibility to a specific state within a multi-state zone. The Transmission Owners propose that if a proposed assignment of costs for a Voluntary Funding Agreement or State Cost Assignment Agreement is accepted by the Commission and such agreement requires the assignment of cost responsibility for a Required Transmission Enhancement to Responsible Customers within the borders of certain states that are part of a multi-state Zone, and neither such agreement nor other agreement approved or accepted by the Commission or the relevant authorities in such states identifies the Responsible Customers in each state, PJM shall identify such Responsible Customers according to the following formula:

CS=(ASPL/AZPL) x CRTE

Where:

- CS is the total cost assigned to Responsible Customers within a state or portion thereof that is part of a multi-state zone

- ASPL is the load of Responsible Customers in a state or portion thereof that is part of a multi-state zone coincident with the annual zonal peak load determined pursuant to Tariff, Schedule 12, section (b)(i)(A)(1)(A)

- AZPL is the zonal peak load determined pursuant to Tariff, Schedule 12, section (b)(i)(A)(1)(A)

- CRTE is the annual revenue requirement of the Required Transmission Enhancement

Proposed subsection (F) further provides that the total cost of a Required Transmission Enhancement assigned to Responsible Customers within a state shall be assigned based on the applicable methodology utilized in such state or Zone. Finally, proposed subsection (F) clarifies that Schedule 12 does not authorize cost assignment based on the state in which such Responsible Customers are located, except as provided under a Voluntary Funding Agreement or a State Cost Assignment Agreement.

F. Proposed Change to Address Required Consultation Post Compliance Cost Allocation Consultations.

Proposed Tariff, Schedule 12, section (b)(xix)(G) provides for consultation between the TOAAC and the Relevant State Entities regarding proposed amendments to Schedule 12, section (b)(xix) following the initial Order No. 1920 compliance filing. Subsection G provides that the TOAAC shall consult with the Relevant State Entities with respect to any such proposed amendments: (1) no less than 30 days prior to any section 205 filing by the TOAAC; and (2) no less than 30 days after receipt of a notice addressed to the Chair of the TOAAC that the PARSEC has agreed to request the TOAAC to make a section 205 filing. Proposed subsection (G) also requires that the results of any such consultation are posted on the PJM Website. Specifically, if the TOAAC initiated the consultation, it shall post the results of the consultation prior to filing the proposed amendment. If the PARSEC initiated the consultation and the TOAAC declines to file the proposed amendment, the results of the consultation will be posted to the PJM Website including an explanation of why the TOAAC declined the proposal. Finally, proposed subsection (G) does not prevent PJM or the PARSEC from filing a proposed amendment to Schedule 12, section (b)(xix) pursuant to section 206.

G. Proposed New Tariff Definitions.

Finally, the Transmission Owners propose to revise the PJM Tariff to add definitions to the Tariff for several terms, some of which are identical to the terms defined in the proposed Operating Agreement amendments to implement the LTRTP. The definitions to All-in-One Plan, Long-Term Regional Transmission Plan, Core Plan, PJM Area Relevant State Entities Committee, and Voluntary Funding Entity refer to the proposed Operating Agreement definitions. The definitions of Voluntary Funding Agreement and State Cost Assignment Agreement refer to their use in Schedule 12, section (b)(xix).

- "All-in-One Plan" shall have the meaning set forth in the Operating Agreement. The PJM December Compliance Filing's proposed revision to the Operating Agreement, Definitions A – B defines All-in-One Plan to mean "a set of Long-Term Transmission Projects addressing Core LT Needs and Additional LT Needs holistically, as determined in accordance with Operating Agreement, Schedule 6-C, section 1.11."[84]

[84] PJM December Compliance Filing, Attach. B, Proposed Revisions to Operating Agreement, Definitions A – B (defining All-in-One Plan).

- "Long-Term Regional Transmission Plan" shall have the meaning set forth in the Operating Agreement. PJM's December Compliance Filing's proposed revision to the Operating Agreement, Definitions I – L, defines Long-Term Regional Transmission Plan to mean "a regional transmission plan developed on a sufficiently long-term, forward-looking, and comprehensive basis that identifies Long-Term Transmission Needs, identifies Long-Term Transmission Projects that meet such needs, measures the benefits of those Transmission Facilities, and evaluates those Transmission Facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional Transmission Facilities to meet Long-Term Transmission Needs with consideration of benefits to consumers relative to costs without overbuilding."[85]

- "Core LT Needs" shall have the meaning set forth in the Operating Agreement. The PJM December Compliance Filing's proposed revision to the Operating Agreement, Definitions C – D, defines Core LT Needs to mean "Long-Term Transmission Needs identified by the Office of the Interconnection in accordance with Operating Agreement, Schedule 6-C, section 1.6.2(a)."[86]

- "Additional LT Needs" shall have the meaning set forth in the Operating Agreement. The PJM December Compliance Filing's proposed revision to the Operating Agreement, Definitions A – B, defines Additional LT Needs to mean "the Long-Term Transmission Needs identified by the Office of the Interconnection in accordance with Operating Agreement, Schedule 6-C, section 1.6.2(b)."[87]

- "PJM Area Relevant State Entities Committee" shall have the meaning set forth in the Operating Agreement. The PJM December Compliance Filing's proposed revision to the Operating Agreement, Definitions O – P, defines PJM Area Relevant State Entities Committee to mean "the voluntary, independent committee consisting of any State entity responsible for electric utility regulation or siting electric transmission facilities within the State or portion of a State located in the PJM Region, including any State entity as may be designated for that purpose by the law of such State. The term PJM Area Relevant State Entities Committee shall mean the committee established through the Organization of PJM States, Inc. in 2024 or any succeeding committee."[88]

- "Voluntary Funding Entity" shall have the meaning set forth in the Operating Agreement, as the Transmission Owners understand PJM will include in a supplemental compliance filing, as discussed in the PJM December Compliance Filing.

- "Core Plan" shall have the meaning set forth in the Operating Agreement. PJM December Compliance Filing's proposed revision to the Operating Agreement, Definitions C – D,

[85] *Id.* at Definitions I – L (defining Long-Term Regional Transmission Plan).

[86] *Id.* at Definitions C – D (defining Core LT Needs).

[87] *Id.* at Definitions A – B (defining Additional LT Needs).

[88] *Id.* at Definitions O – P (defining PJM Area Relevant State Entities Committee).

defines Core Plan to mean "a set of Long-Term Transmission Projects addressing Core LT Needs that, as a portfolio, meets the Core Plan Benefit-to-Cost Ratio, as set forth in Operating Agreement, Schedule 6-C, section 1.10(a)(1)."[89]

The Transmission Owners also propose to revise the PJM Tariff to add the following new definitions, which refer to the use of these terms in Schedule 12, section (b)(xix).

- "Voluntary Funding Agreement" shall mean "an agreement among entities legally authorized to enter into such an agreement and submitted to the Transmission Owners Agreement Administrative Committee" for filing pursuant to Tariff, Schedule 12, sections (b)(xix)(D).

- "State Cost Assignment Agreement" shall mean an agreement among entities legally authorized to enter into such an agreement to assign costs of a Required Transmission Enhancement and submitted to the Transmission Owners Agreement Administrative Committee for filing pursuant to Tariff, Schedule 12, section (b)(xix)(E).

IV. THE PROPOSED COST ALLOCATION METHODOLOGY IS JUST AND REASONABLE AND CONSISTENT WITH THE REQUIREMENTS OF ORDER NO. 1920.

The Transmission Owners' proposed cost allocation methodology satisfies the principles of cost causation, is aligned with the Commission's cost allocation principles set forth in Order No. 1920 and is just and reasonable. Indeed, the Transmission Owners' proposal is based on cost allocation methodologies and processes that have already been found by the Commission to be just and reasonable for use in the PJM region.

For Regional and Necessary Lower Voltage LTRTP facilities, the proposal applies the Commission-approved LRS/SBDFAX hybrid methodology, using a 50/50 ratio for Core Needs projects and a 15/85 ratio for Additional Needs projects to track the different benefits each category provides.[90] For Lower Voltage LTRTP facilities, the proposal retains the 100% SBDFAX methodology the Commission has approved for comparable RTEP projects.[91] The proposal also includes a State Agreement Process that gives states the agency to propose allocation of costs for projects they value and want to prioritize.[92]

Because each element of the Transmission Owners' proposed *ex ante* cost allocation methodology rests on a construct already found just and reasonable in PJM, the methodology

[89] *Id.* at Definitions C – D (defining Core Plan).

[90] This methodology is set forth in PJM Tariff, Schedule 12, section (b)(i)(A) and was found to be just and reasonable in *Long Island Power Auth. v. FERC*, 27 F.4th 705, at 713-14 (D.C. Cir. 2022).

[91] This methodology is set forth in PJM Tariff, Schedule 12, section (b)(iii).

[92] These approaches are set forth in PJM Tariff, Sch. 12, section (b)(xii) and were found to be just and reasonable in *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024, at P 2 (2022).

aligns costs with benefits, avoids incentives to shift projects between planning processes, and satisfies the cost allocation principles of Order No. 1920.

A. The Proposed Revisions Are Based on Cost Assignment Methodologies and Concepts Already Found to Be Just and Reasonable in PJM.

The Transmission Owners developed their proposed cost allocation methodology for LTRTP projects based on cost allocation constructs that the Commission and courts have already found to be just and reasonable, as applied in PJM.[93] That includes that the proposed *ex ante* cost allocation for Regional and Necessary Lower Voltage LTRTP projects is a hybrid methodology of LRS and SBDFAX consistent with the LRS/SBDFAX hybrid methodology for regional reliability RTEP projects in PJM. For Lower Voltage LTRTP projects, the Transmission Owners propose to use a 100% SBDFAX methodology, which the Commission has also already approved for Lower Voltage RTEP projects in PJM. Finally, the Transmission Owners' proposal includes a State Agreement Process that is consistent with the State Agreement Approach the Commission has already approved for RTEP projects.[94]

The Commission has found these foundational principles—hybrid methodology, use of LRS and SBDFAX, and a state agreement option—satisfy the principles of cost causation for RTEP projects in the PJM region. As detailed further below, the application of these foundational principles to LTRTP projects also satisfies the cost causation principles. Accordingly, the Commission should find that the Transmission Owners' proposed cost allocation methodology is just and reasonable.

Cost causation requires the costs assigned to a customer to align with the benefits that customer receives. "To be just and reasonable, rates 'must reflect to some degree the costs actually caused by the customer who must pay for them.'"[95] This principle requires "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[96] LRS, which allocates costs based on zonal load has been approved as meeting the principles of cost causation.[97] LRS methodologies have been approved for projects that provide broad and

[93] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214; *Long Island Power Auth.*, 27 F.4th at 713-14.

[94] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 142, order on reh'g and compliance, 147 FERC ¶ 61,128 (2014), order on reh'g and compliance, 150 FERC ¶ 61,038, order on reh'g and compliance, 151 FERC ¶ 61,250 (2015) ("PJM's State Agreement Approach supplements, but does not conflict with or otherwise replace, PJM's process to consider transmission needs driven by public policy requirements as required by Order No. 1000.").

[95] *Long Island Power Auth. v. FERC*, 27 F.4th at 709 (quoting *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004)).

[96] *Midwest ISO Transmission Owners* 373 F.3d at 1368 (citation omitted); *see also Ill. Com. Comm'n v. FERC*, 576 F.3d 470, 477-78 (7th Cir. 2009); *Ill. Com. Comm'n v. FERC*, 756 F.3d 556, 564-65 (7th Cir. 2014).

[97] *See Ill. Com. Comm'n*, 721 F.3d 764, 780-81 (7th Cir. 2013); *see also ISO New England, Inc.*, 188 FERC ¶ 61,010 (2024) (approving cost of long-term public policy-based projects on a load ratio share basis).

widespread regional benefits. Specifically in PJM, the Commission has found that LRS satisfies cost allocation for RTEP reliability projects[98]—and in other regions, the Commission has found LRS to be an appropriate cost allocation methodology for projects with other primary characteristics, like long-term public policy projects.[99]

SBDFAX in PJM has also been held to satisfy the cost causation principle.[100] Flow-based methodologies, like SBDFAX, analyze the power flows over a specific transmission project to identify the zones benefitting from the project. This analysis is updated annually to keep the cost allocation consistent with current use. The Commission and the courts have approved the use of SBDFAX in PJM because the methodology measures benefits.[101] In doing so, the Commission has noted the methodology is useful for projects that have more specific benefits.[102] Use of a hybrid methodology for Regional Projects which employs LRS and SBDFAX in PJM has already been found to be just and reasonable and consistent with the principles of cost causation.[103]

B. The 1920 Cost Allocation Methodology Proposed for Regional and Necessary Lower Voltage LTRTP Facilities Parallels the Commission-Approved Hybrid Cost Allocation Methodology and Reflects Core and Additional Need Project Benefits.

The Transmission Owners' proposed *ex ante* cost allocation methodology ensures that for each project type in PJM's LTRTP framework, costs are assigned in a manner that is roughly commensurate with benefits on both a regional and sub-regional basis. The Transmission Owners' proposal achieves this just and reasonable outcome by adopting the hybrid cost allocation methodology that the Commission has already approved for PJM RTEP projects[104]

[98] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at PP 414-415, 417-418.

[99] *See ISO New England, Inc.*, 188 FERC ¶ 61,010, at P 39 (2024) (approving cost of long-term public policy based projects on a load ratio share basis).

[100] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 413, 416; *see Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 18 (D.C. Cir. 2021); *Long Island Power Auth.*, 27 F.4th at 713.

[101] *Long Island Power Auth. v. FERC*, 27 F.4th 705, at 713-14 (D.C. Cir. 2022).

[102] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 416.

[103] *Id.* PP 413, 416 (also recognizing that for facilities with broad benefits, such as high-voltage facilities, SBDFAX does not capture all of the broad regional benefits and therefore a hybrid methodology is appropriate; for lower-voltage facilities, SBDFAX alone is just and reasonable); *see Pub. Serv. Elec. & Gas Co.*, 989 F.3d at 18; *Long Island Power Auth.*, 27 F.4th at 713 (citations omitted) ("We too have recognized that high-voltage transmission systems provide 'significant regional benefits' to the PJM network. As for the flow-based component, FERC reasonably looked to usage data as a proxy for specific benefits – in other words, it looked to the data 'to identify the subset of customers that benefit from a facility simply through electrical proximity.'").

[104] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 412–426.

and appropriately tailors the hybrid ratio to reflect the various benefits that Core and Additional Needs projects provide.

The Commission found it just and reasonable for the PJM region to use a hybrid of LRS and SBDFAX to allocate costs for RTEP regional projects. The Commission found[105] that "[t]he postage-stamp [LRS] method recognizes these widespread, although difficult to quantify benefits, by allocating costs to all parties within PJM's integrated network. Additionally, the Solution-Based DFAX method . . . recognize[s] that more specific benefits of projects can be identified over time."[106] The use of the hybrid methodology for RTEP projects in PJM was also upheld by the D.C. Circuit.[107]

Here, the Transmission Owners proposed use of that same hybrid of LRS and SBDFAX methodologies to allocate Regional and Necessary Lower Voltage LTRTP projects is also just and reasonable. Consistent with the hybrid methodology for Order No. 1000, the LTRTP methodology will assign costs both to users that specifically benefit from the projects and who might benefit in the future as usage of the projects changes over time, via SBDFAX, and to all parties within PJM's networks who receive more "difficult to quantify benefits"[108] by using the load-ratio share analysis. The SBDFAX methodology will be the same methodology used for other RTEP projects (including lower voltage projects) and, thus, will be updated annually to ensure it captures changes in the distribution of the benefits of the new transmission facility.[109] As discussed below, the proposed cost allocation methodology also tailors the ratio of SBDFAX to LRS based on the different aspects of the Core Needs and Additional Needs projects to ensure that costs are properly allocated in a manner that is "at least roughly commensurate" with the benefits of the projects.[110] Thus, as it found for RTEP regional projects, the Commission here should likewise find that this hybrid solution is just and reasonable to cost allocate regional LTRTP projects.

1. Proposed Core Projects Ratio Has Already Been Found to be Just and Reasonable for Similar Projects in PJM.

[105] *See id.*

[106] *Id.* P 413.

[107] *Long Island Power Auth.*, 27 F.4th at 713-14.

[108] The Commission described the "difficult to quantify benefits" as "improved reliability, reduced congestion, reduced power losses, greater carrying capability, reduced operating reserve requirements, and improved access to generation." *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 413, 414.

[109] PJM Transmission Owners, Open Access Transmission Tariff Revisions to Modify Cost Allocation for PJM Required Transmission Enhancements, Exhibit No. PTO-2, (Joint Test. Of Michelle Henry & Frank J. Richardson) Docket No. ER13-90, at 22:18-26:8 (Oct. 11, 2012).

[110] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 420 ("We find that evenly apportioning the costs of Regional Facilities reasonably recognizes the meaningful and significant benefits provided to both the overall PJM region and to specific users of Regional Facilities, and will result in costs being allocated in a manner that is at least roughly commensurate with benefits.").

It is just and reasonable for LTRTP Core Needs projects to be allocated at 50% LRS and 50% SBDFAX, as this ratio matches the LRS/SBDFAX ratio for RTEP regional reliability projects. As the Commission found,[111] and the D.C. Circuit upheld,[112] the 50/50 hybrid ratio of LRS and SBDFAX is just and reasonable for RTEP reliability projects. Core Needs projects address multiple criteria including the same reliability and economic project drivers that qualify for the 50/50 ratio applicable to Regional Facility projects under the approved Order No. 1000 cost allocation.[113] They also address other "core" aspects of the PJM system to ensure a reliable transmission system. Thus, both RTEP Regional Facility projects and LTRTP Core Needs projects provide important system-wide benefits. As the Commission found when it approved the RTEP cost allocation for the PJM region, allocating 50% of costs via LRS reflects these system-wide benefits.[114] Like RTEP Regional Facility projects, the LTRTP Core Needs projects also provide specific benefits to those entities that will directly use the projects and the SBDFAX will assign costs both to users that specifically benefit from the projects and who might benefit in the future as usage of the projects changes over time.

Moreover, using the same 50/50 ratio as used for projects planned in PJM under Order No. 1000 provides the additional benefit of avoiding significant changes to cost allocation if the timing of a project changes. For example, a project being considered as part of PJM's LTRTP could be moved into the Order No. 1000 planning cycle if it is determined that the Core Need the project is designed to address must be addressed sooner than the LTRTP planning time frame. PJM should be able to do so without the concern that it would change the project's cost allocation. The same principle should apply to moving a project from the current planning cycle to an LTRTP planning cycle when the need identified is determined not to be as pressing.

Finally, as noted in the PJM December Compliance Filing, there is a possibility that RTEP Regional Facility projects and LTRTP Core Needs projects may provide overlapping or

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[111] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 412-426.

[112] *Long Island Power Auth.*, 27 F.4th at 713-14 ("FERC's decision to approve a hybrid formula incorporating both measures was undoubtedly reasonable given the various benefits of high-voltage facilities. Indeed, it is compelled by precedents finding it arbitrary either to ignore local benefits by using a pure postage-stamp method (*Illinois Commerce*) or to ignore regional benefits by using a pure flow method (*Old Dominion*). As for the selection of a 50:50 ratio for the hybrid formula, the materials we have cited make clear that regional and local benefits are both substantial, thus requiring a significant weight for each component of the formula.").

[113] "Core LT Needs, while driven by maintaining system reliability, can also encompass economic and policy needs." Proposed Sch. 6-C, § 1.6.2. *See* PJM Tariff, Sch. 12, sections (b)(i)(A)(1)(a) and (b).

[114] It is significant that the settlement of the Opinion No. 494 litigation approved by the Commission and affirmed in *Long Island Power Authority* applied the PJM Order No. 1000 hybrid Regional Project cost allocation methodology to the transmission projects at issue in the *Illinois Commerce Commission* case and was supported by eleven of the fourteen PJM states, and no PJM state opposed the settlement. *See PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,168 (2018) at Appendix A, *set aside in part, petitions denied in part and remanded, Long Island Power Auth.*, 27 F.4th 705.

redundant reliability benefits, and under certain circumstances may displace each other.[115] Applying different cost allocation methodologies to functionally overlapping projects based solely upon which planning process is used to identify the project may encourage stakeholders to engage in strategic conduct, including litigation or other means, in an effort to influence the planning process where projects are included. Maintaining the same 50/50 ratio for LTRTP Core Needs and Order No. 1000 projects, as proposed herein, will prevent gaming by eliminating the potential gain from pushing a project from one process to the other in order to obtain a preferred cost allocation.

2. Proposed Additional Needs Projects' Ratio is Just and Reasonable Because it Reflects the Unique Nature of Those Projects

It is also just and reasonable for the LRS/SBDFAX cost allocation ratio for Additional Needs Projects to be more weighted toward SBDFAX than the ratio for Core Needs Projects. Here, the Transmission Owners propose to allocate Additional Needs Projects using 15% LRS and 85% SBDFAX.[116] This approach was adopted in response to PARSEC input during the Engagement Period, where PARSEC expressed that if a hybrid methodology was adopted for Additional Needs projects, the allocation should be substantially weighted toward SBDFAX.

In contrast to Core Needs Projects, Additional Needs Projects focus on drivers associated more closely with addressing state public policy requirements rather than drivers more closely focused on reliability needs.[117] As PJM described in its December Compliance Filing, Additional Needs are "more influenced by the additional drivers which could be different or go beyond those needed to support system reliability."[118] These needs are influenced by state economic and policy initiatives[119] and are not included in the LTRTP to address identified system-wide needs. Therefore, it is more appropriate to allocate a higher percentage of costs according to an analysis of specific beneficiaries. SBDFAX methodology allocates costs based on power flows that reflect the usage of facilities to measure beneficiaries of the facility. It calculates the relative use of a new facility from load in each zone and withdrawals by merchant transmission facilities.[120] Thus, as the Commission recognized that "Solution-Based DFAX method . . . recognize[s] that more specific benefits of projects can be identified over time,"[121] and a greater weight of SBDFAX allocation is just and reasonable for Additional Needs Projects.

However, over time, all transmission customers benefit from high voltage transmission projects, which ultimately become the baseline from which PJM identifies the needs for

[115] PJM December Compliance Filing at 29-31.

[116] Proposed Tariff, Sch. 12, section (b)(xix)(B).

[117] PJM December Compliance Filing at 69 (citation omitted).

[118] *Id.*

[119] *See id.* at 72.

[120] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 348.

[121] *Id.* P 413.

additional enhancements and expansions.[122] Thus, it is appropriate to allocate some portion of the costs to the broader system using the LRS.

For LTRTP Regional and Necessary Lower Voltage Facilities that address both Core and Additional Needs, it is just and reasonable for the cost allocation methodology to assign costs accordingly—the costs to address Core Needs will be assigned according to the Core Needs, 50% LRS and 50% SBDFAX hybrid ratio, and the costs to address Additional Needs will be assigned according to the Additional Needs, 15% LRS and 85% SBDFAX hybrid ratio. This ensures that benefits are roughly commensurate with assigned costs, even when a project combines widespread and usage-specific benefits.

C. The Hybrid Methodology for LTRTP Regional and Necessary Lower Voltage Projects Complies with the Five Cost Allocation Principles Required by Order No. 1920.

The Transmission Owners' proposed cost allocation is consistent with the requirements set forth in Order No. 1920 for LTRTP cost allocation. As described *supra* in section II.D, Order No. 1920 requires that transmission providers' *ex ante* cost allocation comply with the first five of the six regional cost allocation principles set forth in Order No. 1000.[123] In the Order No. 1000 compliance process, the Commission found that the hybrid 50% LRS and 50% SBDFAX methodology complied with these five principles.[124] The same reasoning that the Commission used to find that the Transmission Owners' cost allocation for regional RTEP projects satisfied the first five cost allocation principles also applies to the Transmission Owners' proposed cost allocation for LTRTP Core Needs Projects.

1. The Proposed Methodology for Core Needs Projects Satisfies Cost Allocation Principles 1 and 2.

The Commission found that the 50/50 hybrid methodology satisfied principles 1 (*i.e.*, that costs be allocated in a manner that is roughly commensurate with benefits received) and 2 (*i.e.*, that costs are not allocated to entities with little to no benefits) because it blended "recognition of broad, regional benefits with specifically identifiable benefits over time."[125] The Commission

[122] *Id.* P 414 ("[A]n advantage of [the LRS] method is that it captures the full spectrum of benefits associated with high-voltage facilities, including difficult to quantify regional benefits, such as improved reliability, reduced congestion, reduced power losses, greater carrying capacity, reduced operating reserve requirements, and improved access to generation. . . . [T]his postage stamp method accounts for changes in system use over the lifetime of a high-voltage facility. Because all customers in the region will share these broad regional benefits, a postage-stamp component of cost allocation is a reasonable way to allocate costs to consumers that are roughly commensurate with such benefits.").

[123] Order No. 1920 at P 1471.

[124] 142 FERC ¶ 61,214 at P 412. The DC Circuit similarly recognized that the 50/50 hybrid methodology was appropriate for Regional Facilities given their direct and local benefits are both substantial, thus requiring a significant weight for each component. *Long Island Power Auth.*, 27 F.4th at 713-14.

[125] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 413.

also found that it "represents a reasonable balance" of both the broad and specific benefits of regional projects.[126] That reasonable balance is also appropriate for the ratio used for Core Projects, because like Regional RTEP Projects, they provide similarly broad and specific benefits to the PJM region. "[R]atemaking is not an exact science."[127] Here the benefits need not be exact but "roughly commensurate" to satisfy Principle 1. In the Order No. 1000 Compliance Order, the Commission also rejected arguments by certain states suggesting that a different split was appropriate, finding that "the PJM Transmission Owners need only show that the instant proposal is just and reasonable and otherwise consistent with the requirements of Order No. 1000."[128]

Regarding Principle 2, the costs are not allocated to "[t]hose that receive no benefit from [the] transmission facilities."[129] SBDFAX identifies specific beneficiaries and through LRS costs are allocated to other customers in the region who receive some benefit from the facilities due to their broad regional nature. As it did in Order No. 1000, the Commission should find the 50/50 hybrid methodology that the Transmission Owners are proposing for LTRTP Core Needs Projects satisfies the first and second principles.

2. The Proposed Methodology for Additional Needs Projects Satisfies Cost Allocation Principles 1 and 2.

While the Transmission Owners' proposed hybrid ratio for Additional Needs Projects is different than that for Core Needs Projects, these same reasons still apply to support a finding that the Additional Needs cost allocation satisfies the first two principles. Because Additional Needs Projects focus more on addressing specific state sponsored public policy needs, a greater percentage should be allocated to specific users rather than the share allocated based on the general reliability and system needs. While these projects may also address some broad, regional benefits, those benefits were not sufficient to include the projects in the All-in-One Plan. Rather it is state-driven policy goals that make these projects candidates for inclusion in the All-in-One Plan. Thus, a smaller percentage of LRS and a larger percentage of SBDFAX is appropriate. A larger SBDFAX percentage reflects that the benefits of Additional Needs Projects are more likely to be focused on the states and regions from which those policies emerge. Again, because "ratemaking is not an exact science," there may be a range of ratios that would ensure benefits are roughly commensurate with costs. Accordingly, to properly balance that ratio, the Transmission Owners propose to adopt ratios designed to ensure costs are allocated roughly

[126] *Id.* P 417.

[127] *FPC v. Conway*, 426 U.S. 271, 278 (1976).

[128] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 418. *See Long Island Power Auth.*, 27 F.4th at 714 ("[A]ny debate over the choice between a 50:50 ratio and, say, a ratio of 60:40 one way or the other would 'amount to a quibble about exacting precision,' rather than 'a wholesale departure from the cost-causation principle.'" (quoting *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1261 (D.C. Cir. 2018))).

[129] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 637.

commensurate with the level of benefits entities receive, and to align with the principles advanced by PARSEC during the Engagement Period.

3. The Proposed Methodology for Both Core and Additional Needs Projects Satisfies Cost Allocation Principles 3, 4, and 5.

The Commission should find that the Transmission Owners' proposed LTRTP *ex ante* cost allocation for both the Core Needs and Additional Needs hybrid methodologies satisfies the cost allocation principles 3, 4, and 5. Regarding Principle 3 (*i.e.*, a benefit to cost threshold should not exceed 1.25 to 1), PJM will use a threshold of 1:1 for Core Projects and 1.25 to 1 for Additional Needs Projects.[130]

With regard to principle 4 (*i.e.*, costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs), the Commission found that PJM Tariff Schedule 12's definition of Required Transmission Enhancement, which includes projects outside PJM pursuant to the agreements listed in Schedule 12 Appendix B, satisfied this requirement.[131] Here, the Transmission Owners' proposed tariff language for both Core Needs and Additional Needs cost allocation use the same defined term "Required Transmission Enhancement" and the Commission should therefore find it also satisfies principle 4.

For principle 5 (*i.e.*, the cost allocation method must be transparent), the Commission found that PJM Tariff Schedule 12 contained sufficiently detailed language to allow a stakeholder to reproduce the results of LRS and SBDFAX.[132] The Transmission Owners' proposed tariff language for both Core Needs and Additional Needs cost allocation applies this same language in Schedule 12, section (b)(i) and (b)(iii), to describe the LRS and SBDFAX methodologies, and thus, continues to satisfy the fifth principle.

[130] PJM December Compliance Filing at 69.

[131] *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,128, at PP 332, 335 (2014).

[132] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 423.

4. The Proposed Methodology for Both Core and Additional Needs Projects Does Not Assign Cost Allocation by Project Type.

Order No. 1000 included a Cost Allocation Principle 6 (*i.e.*, a different cost allocation method may be used for different types of transmission facilities), but Order No. 1920 specifies that the cost allocation for Long-Term Regional Transmission projects cannot allocate costs by project type.[133] Here, while the Transmission Owners' proposed cost allocation distinguishes between Core Needs projects and Additional Needs projects, it does not allocate costs by project type because neither Core Needs nor Additional Needs projects are specific to any one project type like the reliability, economic, and public policy projects contemplated by Order No. 1000. Rather, each responds to a range of needs driven by the various factors considered by PJM in the planning process. Thus, the different hybrid ratios for Core Needs and Additional Needs projects function to ensure costs are roughly commensurate with benefits, based on the range of needs that each project category is likely to address and the benefits it will provide, and the different hybrid ratios do not create distinct cost allocation based on project type.

D. Proposed Cost Allocation for Lower Voltage LTRTP Facilities Is Just and Reasonable and Complies with the Cost Allocation Principles Required by Order No. 1920.

The Commission found the PJM Tariff Schedule 12 cost allocation of Lower Voltage Facilities using 100% SBDFAX to be just and reasonable and consistent with the Order No. 1000 cost allocation principles.[134] Specifically, the Commission found that SBDFAX will "result in cost allocation for lower voltage projects that is roughly commensurate with the benefit derived through use of the new facility."[135] Here, there is no change in the local nature of these Lower Voltage Facilities despite the fact that they will be addressing long-term planning needs. Accordingly, it is just and reasonable and compliant with Cost Allocation Principle 1 to continue allocating the costs of those facilities using SBDFAX. Because the costs will be allocated to specifically identified beneficiaries using SBDFAX, it also satisfies Cost Allocation Principle 2.

Regarding Principle 3, PJM will use a threshold of 1:1 for Core Projects and 1.25 to 1 for Additional Needs Projects.[136]

With regard to principle 4, as noted above, the Commission has found that PJM Tariff Schedule 12's definition of Required Transmission Enhancement satisfies this requirement.[137]

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[133] Order No. 1920 at P 1475.

[134] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 431.

[135] *Id.*

[136] PJM December Compliance Filing at 69.

[137] *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,128 at PP 332, 335.

Finally, as noted above, principle 5 is satisfied because PJM Tariff Schedule 12 contains sufficiently detailed language to allow a stakeholder to reproduce the results of LRS and SBDFAX.[138]

E. The Proposed State Agreement Process and State Cost Assignment Agreement is Just and Reasonable and Complies with the Requirements of Order No. 1920.

Order No. 1920 allows for a State Agreement Process to be used in addition to the required *ex ante* cost allocation methodology.[139] The Final Rule defines a State Agreement Process to be:

> [A] process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation.[140]

Order No. 1920 also requires a transmission provider that chooses to file any State Agreement Process agreed to by the Relevant State Entities to propose tariff revisions that describe the State Agreement Process.[141]

Order No. 1920-A further requires transmission providers to file a State Agreement Process at the request of the Relevant State Entities, if the Relevant State Entities reach agreement on a State Agreement Process and notify the transmission provider by the deadline for communicating such agreement.[142] Order No. 1920-A, however, does not require the transmission provider to characterize a State Agreement Process attached to its compliance filing at the request of the Relevant State Entities.[143]

In April 2026, the PARSEC notified the Transmission Owners that it had reached agreement on a State Agreement Process and requested that Transmission Owners attach its process to this compliance filing.[144] The Transmission Owners are attaching the PARSEC proposal as required by Order No. 1920-A.[145]

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[138] Tariff, Sch. 12, § (b)(i), (b)(iii).

[139] Order No. 1920 at P 1402.

[140] *Id.*

[141] *Id.* P 1403.

[142] Order No. 1920-A at P 651.

[143] *Id.* P 655.

[144] Thomas Decl. ¶ 22.

[145] *See supra*, p. 2 (reiterating that the Transmission Owners have included certain PARSEC filings as attachments to their filings under protest and without prejudice to their rights).

The Transmission Owners have developed their own just and reasonable State Agreement Process that is consistent with the existing Order No. 1000 State Agreement Approach already approved by the Commission for the PJM region.[146] The proposed State Agreement Process for LTRTP projects is slightly modified from the existing State Agreement Approach to address Order No. 1920's requirement to describe different aspects of the State Agreement Process. The Transmission Owners' proposed State Agreement Process applies to both Core and Additional Needs projects and reflects the Transmission Owners' understanding of a desire by the PARSEC to have flexibility for states seeking to utilize the State Agreement Process. The Transmission Owners proposed State Agreement Process provides the states with the agency to modify the allocation for specific projects if the PARSEC believes such a change is necessary. This further bolsters the just and reasonableness of the Transmission Owners overall cost allocation proposal.

1. The Transmission Owners' Proposed State Agreement Process Tariff Language Complies with Order No. 1920's Requirements for Specific Aspects of a State Agreement Process to be Described in the Tariff.

The Order requires that the tariff provisions describe key information on how the State Agreement Process will result in a cost allocation being filed, including: (a) which entities may participate in the State Agreement Process; (b) what constitutes an agreement on cost allocation in that process; (c) how agreement is communicated to the transmission providers; and (d) the circumstances under which, or the information necessary for, transmission providers to file or to consider filing the agreed cost allocation method.[147] The proposed tariff language complies with these requirements by specifying that: (a) the PARSEC can submit a State Cost Assignment Agreement to the TOAAC for consideration, (b) the Transmission Owners will rely on the PARSEC's assertion that they have reached an agreement pursuant to their process, (c) the PARSEC can communicate its agreement by submitting the State Cost Assignment Agreement to the Transmission Provider (*i.e.*, the PJM Office of Interconnection) and (d) the Transmission Provider submits such agreement to the TOAAC in order for the Transmission Owners to consider filing it.[148]

The Order further requires that the tariff language describing the State Agreement Process include (1) the event triggering the beginning of the State Agreement Process, (2) the duration of the State Agreement Process (not to exceed six months after selection), and (3) a description of the Long-Term Regional Transmission Facilities to which the process applies.[149] The proposed tariff language complies with these requirements by specifying that: (1) the PJM Board's approval of the LTRTP triggers the beginning of the six-month State Agreement Process, (2) a State Cost Assignment Agreement must be provided to the Transmission Provider

[146] PJM Tariff Sch. 12, section (b)(xii)(B); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 124.

[147] Order No. 1920 at P 1403.

[148] Proposed Tariff, Sch. 12, section (b)(xix)(E).

[149] Order No. 1920 at P 1416.

within six months of the approval of the LTRTP, and (3) the State Agreement Process applies to transmission facilities selected for the LTRTP.

With regard to the time period for developing a cost allocation under a State Agreement Process, the Order requires that any State Agreement Process must be completed, *i.e.*, any resulting cost allocation method must be filed with the Commission, no later than six months after selection of the applicable Long-Term Regional Transmission Facility (or portfolio of such Facilities).[150] The proposed tariff language complies with this requirement because it requires any State Cost Assignment Agreement that results from a State Agreement Process to be provided to PJM, which in turn submits the State Cost Assignment Agreement to the Transmission Owners for filing within six months of the approval of an LTRTP.[151]

The tariff also must describe the manner in which a transmission provider would file a section 205 filing to seek Commission acceptance of a cost allocation method resulting from a State Agreement Process.[152] The proposed tariff language complies with this requirement by describing that if the TOAAC approves the State Cost Assignment Agreement pursuant to the voting requirements prescribed by the CTOA, the TOAAC will file a State Cost Assignment Agreement under section 205 of the FPA. This tariff language is consistent with the Final Rule, which clarifies that it does not create any obligation that transmission providers file a cost allocation method resulting from a State Agreement Process.[153] The proposed tariff language imposes no such obligation on the Transmission Owners, and clarifies that if the Transmission Owners decline to file a State Cost Assignment Agreement under section 205, nothing in the tariff prevents PJM or the Relevant State Entities from filing such agreement under section 206.[154] This process is identical to the Commission-accepted State Agreement Approach in the PJM Tariff.[155]

2. The Transmission Owners' Proposed State Agreement Process Preserves the Transmission Owners' Section 205 Filing Rights, Consistent with the Requirements of Order No. 1920 and Relevant Legal Precedent.

The State Agreement Process proposed by the Transmission Owners is just and reasonable. Consistent with the structure and text of the FPA, it preserves the Transmission Owners' exclusive and unilateral rights to make section 205 filings regarding any changes related to establishment and recovery of the Transmission Owners' transmission revenue requirements or the transmission rate design under the PJM Tariff. The State Agreement Process

[150] *Id.* P 1406.

[151] Proposed Tariff, Sch. 12, section (b)(xix)(E).

[152] Order No. 1920 at P 1416.

[153] *Id.* P 1412.

[154] Proposed Tariff, Sch. 12, section (b)(xix)(E).

[155] PJM Tariff, Sch. 12, section (b)(xii)(B).

also ensures compliance with the PJM Tariff and the CTOA. Specifically, the State Agreement Process only requires the filing of a State Cost Assignment Agreement under section 205 by the Transmission Owners if the TOAAC approves the State Cost Assignment Agreement consistent with the requirements of the CTOA.

Retention of these filing rights is supported by legal precedent. In *Atlantic City Electric v. FERC*, the D.C. Circuit held that "section 205 of the [FPA] gives a utility the right to file rates and terms for services rendered with its assets."[156] The Commission may not contravene these filing rights as in doing so it would exceed its authority under sections 205 and 206 of the FPA, as the FPA does not authorize the Commission to require public utilities to cede their filing rights.[157] The Commission acknowledged this limitation in Order No. 1920 by not requiring the transmission provider to file a cost allocation resulting from a State Agreement Process if it did not approve it. Thus, it is consistent with the requirements of Order No. 1920 and relevant legal precedent for the tariff language to provide that the Transmission Owners may decline to file a State Cost Assignment Agreement if the agreement is not voted out of the TOAAC consistent with the requirements of the CTOA.

F. The Transmission Owners Propose a Voluntary Funding Agreement for LTRTP Projects That Are Not Selected for the All-in-One Plan.

Order No. 1920 requires each transmission planning region to include in its tariff "a process to provide Relevant State Entities and interconnection customers an opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility" that does not meet the planning selection criteria to be included in the LTRTP.[158]

1. The Transmission Owners' Proposed Tariff Language Satisfies Order No. 1920's Requirements.

The Order requires this voluntary funding process to be transparent, not unduly discriminatory or preferential, and for the tariff to describe: (1) the process for making voluntary funding opportunities available, including timely notice of such opportunities and a meaningful opportunity to take advantage of the option; (2) the period during which Relevant State Entities and interconnection customers may exercise the option to provide voluntary funding; (3) the method that will be used to determine the amount of voluntary funding required for the facility to be included in the LTRTP; and (4) the mechanism to memorialize any voluntary funding agreement.[159] The first three of these requirements reflect planning requirements and will be addressed by PJM in Schedule 6-C of the Operating Agreement. As PJM described in its December compliance filing, it "expects the Voluntary Funding Agreement process that it will

[156] 295 F.3d 1, 9 (D.C. Cir. 2002) (citation omitted).

[157] 16 U.S.C. § 824d(d); *Atlantic City*, 295 F.3d at 9-11; *Commonwealth of Mass., Dep't of Pub. Utils. v. FERC*, 729 F.2d 886, 888 (1st Cir. 1984) ("*MA DPU")*.

[158] Order No. 1920 at P 1012.

[159] *Id.* P 1013.

develop to 'provide ample notice and time for states and long-term transmission developers to identify and evaluate proposals they may want to fund, to post information for the voluntary funding opportunity, and to take sufficient time to make voluntary funding decisions.'"[160] Furthermore, PJM "expects to develop a *pro forma* voluntary funding agreement to memorialize such commitments."[161] These provisions will be housed in Operating Agreement Schedule 6-C, section 1.14, which PJM has reserved for a description of the voluntary funding process.

Regarding requirement 4, the need to identify a mechanism to memorialize any voluntary funding agreement, the Transmission Owners propose Schedule 12, section (b)(xix)(D) to satisfy this requirement. The tariff language describes the process for submitting a Voluntary Funding Agreement for consideration for filing: the Voluntary Funding Entity proposes a Voluntary Funding Agreement to the Transmission Provider (*i.e.*, PJM's Office of Interconnection) and then the Transmission Provider submits such agreement to the TOAAC. The tariff language also describes the process for filing a Voluntary Funding Agreement with the Commission: if the TOAAC votes to approve a Voluntary Funding Agreement, the TOAAC files the Voluntary Funding Agreement under section 205. If it declines to file the agreement, PJM or the Voluntary Funding Entity can file the agreement under section 206.

The Order also provides that transmission providers must consult with and seek support from Relevant State Entities when developing the voluntary funding process.[162] The Transmission Owners have satisfied this requirement by facilitating a nearly 24-month Engagement Period with the PARSEC, including two meetings in March 2026 where the Transmission Owners noted that they were developing tariff language for the voluntary funding process and provided question and answer time for the PARSEC members.[163] These meetings occurred ahead of the Transmission Owners finalizing their voluntary funding process tariff language.

2. The Voluntary Funding Process Is Just and Reasonable.

The proposed voluntary funding process ensures that any Voluntary Funding Agreement that goes into effect in the PJM region will be just and reasonable and satisfy cost causation principles because the agreement will have to be approved by the Commission under either section 205 or section 206.[164]

The proposed voluntary funding process also preserves the Transmission Owners' section 205 filing rights by providing the Transmission Owners the opportunity to decline to file a

[160] PJM December Compliance Filing at 125.

[161] *Id.*

[162] Order No. 1920 at P 1012.

[163] Thomas Decl. ¶ 8.

[164] *See* Proposed Tariff, Sch. 12, section (b)(xix)(D) (describing that any Voluntary Funding Agreement will be submitted to the Commission for approval either by the Transmission Owners under section 205 or by PJM or a Voluntary Funding Entity under section 206).

Voluntary Funding Agreement that is submitted to the TOAAC. As explained in section IV.E.2, *supra*, with regard to the proposed State Agreement Process, the FPA does not give the Commission authority to contravene a public utility's right to file its own rates under section 205.[165]

V. THE PJM TRANSMISSION OWNERS PROPOSE ADDITIONAL TARIFF CHANGES THAT WILL ALLOW THEM TO COMPLY WITH THE REQUIREMENTS OF ORDER NO. 1920.

A. The Methodology to Assign Cost Responsibility for States or States Within a Multi-State Transmission Zone Is Necessary to Allow the Transmission Owners to Properly Comply with Order No. 1920.

A cost allocation resulting from a Voluntary Funding Agreement process or a State Agreement Process may require analysis of cost responsibility for certain specific states, even if those states are part of a multi-state zone. Schedule 12 and the proposed changes to Schedule 12 in this filing are designed to allocate costs to specific transmission zones in PJM. However, if a State Cost Assignment Agreement or Voluntary Funding Agreement approved by the Commission requires the allocation of costs to a single state within a multi-state zone, it will need a mechanism to do so. Thus, the Transmission Owners developed a method to assign cost responsibility to a specific state within a multi-state zone if so required, as described above in Proposed Tariff, Schedule 12, section (b)(xix)(F).

This tariff change to assign costs to a single state within a multi-state zone is necessary to comply with the requirements of Order No. 1920, because Order No. 1920 requires a transparent and not unduly discriminatory voluntary funding process.[166] The process starts by first looking to the Voluntary Funding Agreement or State Cost Assignment Agreement, which may contain a specific allocation or method for allocating costs to specific states in a multi-state zone. Absent such a method, the Tariff provides for use of any existing process accepted by the Commission or by the relevant states to assign costs to specific states. In this way, the intent of the Voluntary Funding Agreement parties is given preference followed by existing Commission-approved agreements or existing relevant state processes. Only if there is no mechanism to measure cost assignment to a single state within a multi-state zone does the mechanism for allocating those costs proposed in Section (b)(xix)(F) come into play. The mechanism proposed is fully transparent relying on zonal and state peak load information measured to allocate the LRS portion of Regional Facility cost responsibility assignments under Schedule 12.[167]

[165] *See supra* nn. 156, 157.

[166] Order No. 1920 at P 1012.

[167] PJM Tariff, Sch. 12, section (b)(i)(A)(1).

B. Consultation Process with Relevant State Entities for Future Changes to LTRTP Cost Allocation.

Order No. 1920-A requires transmission providers to consult with Relevant State Entities regarding potential future changes to *ex ante* cost allocation methods and State Agreement Processes used in the LTRTP.[168] This consultation must occur: (1) prior to the Transmission Owners amending the LTRTP cost allocation methodology or State Agreement Process or (2) when the Relevant State Entities seek to amend the LTRTP cost allocation methodology or State Agreement Process.[169] Specifically, Order No. 1920-A requires transmission providers to include in their OATTs a description of how they will consult with Relevant State Entities in these circumstances.[170] The Transmission Owners' Proposed Tariff, Schedule 12, section (b)(xix)(G) complies with these requirements because it requires the TOAAC to consult with the Relevant State Entities in PJM either no less than 30 days prior to making a section 205 filing to amend section (b)(xix) of Schedule 12 or no less than 30 days of receiving notice addressed to the Chair of the TOAAC that the Relevant State Entities have agreed to request that the TOAAC make a section 205 filing to amend section (b)(xix) of Schedule 12. Furthermore, while Order No. 1920-A did not specify the amount of time prior to filing an amendment that a transmission provider must consult with the Relevant State Entities, the Transmission Owners propose a 30-day prior to filing requirement that is consistent with the other TOAAC notice requirements provided in the PJM Tariff.[171]

Order No. 1920-A also requires transmission providers to post the results of such consultation in certain circumstances. For a consultation initiated by the transmission providers, it requires transmission providers to document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities prior to filing their amendment.[172] For a consultation initiated by Relevant State Entities, if the transmission providers choose not to propose any amendments preferred by Relevant State Entities, the Order requires transmission providers to document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities, including an explanation for why they have chosen not to propose any amendments.[173] The Transmission Owners' proposed tariff language complies with these requirements because it requires the TOAAC to post on the PJM Website the results of consultation with the Relevant State Entities pursuant to subsection (G): if the TOAAC initiated the consultation, it must post the results of the consultation prior to filing the amendment; if the Relevant State Entities initiated the consultation and the TOAAC is declining

[168] Order No. 1920-A at PP 12, 691.

[169] *Id.* P 13.

[170] *Id.* P 691.

[171] See PJM Tariff, Section 9.

[172] Order No. 1920-A at P 691.

[173] Order No. 1920-A at P 691.

to file the amendment, the TOAAC must post the results of the consultation including an explanation of why it has declined to propose the amendment.

The proposed consultation language complies with the requirements of Order No. 1920, however, as noted above those requirements violate the Transmission Owners' rights under the FPA and the First Amendment.[174] While, consistent with a public utility's FPA right to file its own rates under section 205, the Commission has not required the Transmission Owners to file the states' proposal, neither the FPA nor the First Amendment authorize the Commission to require the Transmission Owners to explain their decision not to file another entity's tariff proposal.

VI. THE PJM TRANSMISSION OWNERS COMPLIED WITH THE ORDER NO. 1920 REQUIREMENTS TO MEET WITH PARSEC AND TO ATTACH PARSEC'S COST ALLOCATION PROPOSAL.

A. Engagement Period for Cost Allocation Negotiations.

Order No. 1920 requires transmission providers to meet with the Relevant State Entities in their region during a specified Engagement Period. The Order required the Engagement Period to be a six-month period during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities.[175]

With regard to the first requirement, Order No. 1920 specifies that notice means a posting on the transmission provider's OASIS page or public website, or the equivalent thereof, of the opportunity for any Relevant State Entity to participate in, and the starting and end dates of, the Engagement Period.[176] The Transmission Owners complied with this requirement by posting notice of the beginning date and projected end date of the Engagement Period on PJM's website.[177] The Transmission Owners also coordinated with OPSI leadership to have a virtual kickoff meeting on September 9, 2024, which was held before the formal start of the

[174] *See*, *supra*, FPA and First Amendment discussion at p. 2.

[175] Order No. 1920 at PP 5, 1354. If the Transmission Owners decline to file an amendment at the request of the Relevant State Entities, the Relevant State Entities are still able to file such amendment under section 206.

[176] *Id.* P 1356.

[177] Thomas Decl. ¶ 9; PJM, Transmission Expansion Advisory Committee, https://www.pjm.com/committees-and-groups/committees/teac.

Engagement Period on October 7, 2024.[178] The Transmission Owners also worked with OPSI and other state leaders to develop an inclusive mailing list for meeting invitations and distributions.

With regard to the second requirement, Order No. 1920 specifies that the notice must include contact information for a single point of contact in the transmission planning region that the Relevant State Entities can use to communicate any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement, must be no earlier than the end date of the Engagement Period.[179] The Transmission Owners complied with this requirement by including in their posting the email contact information for one of the Transmission Owners' counsel and the deadline to communicate an agreement.[180] That date was changed each time the Engagement Period was extended to reflect the extension. The Transmission Owners also agreed with the PARSEC to extend the date to September 25, 2026, as negotiations were ongoing up until then.[181]

With regard to the third requirement, for the transmission providers to provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities, the Transmission Owners complied by hosting regular meetings throughout the close to 24-month Engagement Period. Over the course of the initial Engagement Period prior to engaging DRS, the Transmission Owners and PARSEC held 14 formal meetings.[182] These meetings provided an opportunity for any PARSEC member to ask a question or to provide a comment on the discussion. Furthermore, the first few months of meetings focused on education; the Transmission Owners provided education to the PARSEC members on various just and reasonable cost allocation methodologies. This was done with the goal of creating a baseline understanding for the cost allocation negotiations. While Order No. 1920-A specifically added the requirement that, upon the request of Relevant State Entities, transmission providers must facilitate and participate in a cost allocation discussion during the Engagement Period with Relevant State Entities,[183] the Transmission Owners and the PARSEC were already engaged in a cost allocation discussion process by the time the Commission issued Order No. 1920-A.

[178] Thomas Decl. ¶ 6.

[179] Order No. 1920 at P 1356.

[180] PJM, Transmission Expansion Advisory Committee, https://www.pjm.com/committees-and-groups/committees/teac.

[181] Thomas Decl. ¶ 19.

[182] *Id.* at ¶ 8.

[183] Order No. 1920-A at PP 651, 656.

B. PJM Transmission Owners Made A Robust and Sincere Effort To Reach Agreement on A Cost Allocation Methodology.

Throughout the Engagement Period, the Transmission Owners made a sincere effort to work with the PARSEC to develop a cost allocation methodology that both parties could accept. These efforts included early education sessions designed to respond to PARSEC requests and to provide the PARSEC with the information its members would require in the process as well as numerous discussions in which the Transmission Owners were able to listen and internalize thoughts from State Commissioners and Staff as well as PARSEC leadership.[184]

As noted above, the Engagement Period culminated with the Transmission Owners adopting several concepts they understood to be of interest to the PARSEC in their own initial proposal presented to the PARSEC in March 2026.[185] These concepts are reflected in the Transmission Owners' proposed Tariff language, and terms included: (1) a hybrid methodology using PJM's existing SBDFAX and LRS methodologies for Regional Facilities, (2) use of SBDFAX for Lower Voltage Facilities, (3) a State Agreement Process, and (4) a method to identify state-specific benefits within a multi-state zone.[186]

Despite these sincere efforts, the Transmission Owners and PARSEC were unable to reach agreement on all aspects of a cost allocation methodology. In late March and early April 2026, each group presented the cost allocation methodology that their group had agreed upon to the other group.[187] There were significant similarities between each method—particularly due to the Transmission Owners' efforts to adopt cost allocation concepts in which the PARSEC had expressed interest over the course of the Engagement Period. However, despite multiple attempts to reach consensus, a consensus was not reached at that time.[188]

The Transmission Owners and PARSEC renewed their efforts to reach agreement in the summer of 2026, by consensually seeking use of the Commission's DRS resources. Both sides engaged in this process in good faith, and additional areas of agreement were identified. The Transmission Owners' proposal herein reflects those areas. Although the Transmission Owners and PARSEC were unable to reach a final settlement, the Transmission Owners believe (and this proposal reflects) that substantial agreement on key areas was achieved, and that the remaining areas of dispute reflect sincerely held disagreements that were meaningfully challenged during negotiations.

[184] Thomas Decl. ¶¶ 10-12.

[185] *Id.* at ¶¶ 14-16, 18, 20, 23.

[186] *Id.*

[187] *Id.* at ¶ 13.

[188] *Id.* at ¶ 17.

C. Requirement to Attach Alternative Cost Allocation and/or State Agreement Process at the Request of the Relevant State Entities.

Order No. 1920-A further requires transmission providers to attach to their cost allocation compliance filing, at the Relevant State Entities' request, the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process.[189] This attachment also must include any information that Relevant State Entities provide to them regarding the state negotiations during the Engagement Period.[190] Specifically, transmission providers must include "any and all supporting evidence and/or justification related to Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process that Relevant State Entities request that transmission providers include in their compliance filing," which Order No. 1920-A notes could include, for example, "a description of the discussions that took place at the Engagement Period forum for negotiation and whether each Relevant State Entity agreed or disagreed with the cost allocation method proposed on compliance."[191] Order No. 1920-A clarifies, however, that it does not require transmission providers to independently characterize this information.[192]

As required by Order No. 1920-A, the Transmission Owners are including in Attachment D all of the materials that the PARSEC has requested they include. Transmission Owners have petitioned for review of Order No. 1920-A's requirement to attach as part of their compliance filing the Relevant State Entities' cost allocation proposal and any materials provided by the Relevant State Entities as a violation of their rights under the FPA and the First Amendment to the U.S. Constitution.[193] Notwithstanding the pending appeal, the Transmission Owners are complying with this requirement by attaching materials, at the PARSEC's request, that detail the PARSEC's alternative cost allocation proposal and State Agreement Process.[194] As noted above, the Transmission Owners are complying with Order No. 1920-A's requirement under protest.

VII. EFFECTIVE DATE

The Transmission Owners request that the Commission accept the amendments to the PJM Tariff without hearing, modification, or condition effective on the effective date that the Commission accepts for PJM's LTRTP. On December 12, 2025, PJM filed, pursuant to section 205 of the FPA, proposed amendments to the PJM Operating Agreement to implement the LTRTP Protocol to satisfy the requirements of Order No. 1920. It entered a placeholder effective date of 12/31/9998 and, once the Commission issues an order on its filing, PJM will submit a clean-up filing to enter the actual effective date. The Transmission Owners respectfully

[189] Order No. 1920-A at P 651.

[190] *Id.*

[191] *Id.* P 655.

[192] *Id.*

[193] *Appalachian Voices, et al., v. FERC*, No. 24-1650 (4th Cir. 2026).

[194] *See* Attachment D.

request that such Operating Agreement amendments and the instant amendments to the PJM Tariff be given the same effective date and have likewise entered a placeholder effective date of 12/31/9998. Once the Commission issues an order on its filing, the Transmission Owners will submit a clean-up filing to enter the actual effective date, matching that requested in PJM's clean-up filing.

VIII. CORRESPONDENCE AND COMMUNICATIONS

The PJM Transmission Owners request that all correspondence, pleadings, and other communications concerning this filing be served upon the following:[195]

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IX. ADDITIONAL INFORMATION REQUIRED BY REGULATION 35.13(B)

A. Contents of Filing

This filing consists of the following documents:

- The instant Transmittal Letter
- Attachment A: Redlined Tariff Sheets showing proposed amendment to PJM Tariff, Schedule 12, section (b)(xix)
- Attachment B: Clean Tariff Sheet of proposed amendment to PJM Tariff, Schedule 12, section (b)(xix)
- Attachment C: Declaration of Amber Thomas
- Attachment D: PARSEC Materials

B. Service

On behalf of the Transmission Owners, 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,[196] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order, with a specific link to the newly filed documents, and will send an email on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[197] alerting them that this filing has been made by PJM and is available by following such link. If the documents are not immediately available by using the referenced link, the documents will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp, in accordance with the Commission's regulations and Order No. 714.

C. Description of and Reason for Rate Change

A detailed description of the rate change is included in section III above.

D. Agreement Required for Rate Change

The amendment to Schedule 12 has been authorized pursuant to a vote of the TOAAC pursuant to CTOA § 8.5.1.

E. Request for Waivers

The information submitted with this filing substantially complies with the requirements of Part 35 of the Commission's rules and regulations applicable to filings of this type. To the extent necessary, the Transmission Owners request waiver of the requirement to submit cost-of-service data required by 18 C.F.R. § 35.13. Further, the Transmission Owners request a waiver of any applicable requirement of Part 35 for which a waiver is not specifically requested, if necessary, to permit this filing to become effective as proposed.

[195] The Transmission Owners respectfully request a waiver of 18 C.F.R. § 385.203(b)(3) to permit service on more than two persons.

[196] 18 C.F.R. §§ 35.2(e), 385.2010(f)(3).

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

X. CONCLUSION

For the reasons discussed above and in the attachments to this transmittal letter, the PJM Transmission Owners submit this filing to implement the requirements of Order Nos. 1920 and 1920-A and request that the Commission accept new Schedule 12, section (b)(xix) and related new PJM Tariff definitions as compliant with the cost allocation requirements of said orders without hearing, modification or condition. The Transmission Owners request that the Commission allow these changes to become effective on the effective date that the Commission accepts the PJM December Compliance Filing and the TO December Compliance Filing and have likewise requested a placeholder effective date of 12/31/9998. Once the Commission issues an order on this filing, the Transmission Owners will submit a clean-up filing to enter the actual effective date.

Sincerely,

/s/ William M. Keyser

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November 19, 2026

Attachment A

Revisions to the PJM Open Access Transmission Tariff

(Marked Format)

Included within this Attachment A:

- Definitions A-B
- Definitions C-D
- Definitions L-M-N
- Definitions O-P-Q
- Definitions R-S
- Definitions T-U-V
- Schedule 12

Definitions – A - B

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

"Abnormal Condition" shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Additional LT Needs:

"Additional LT Needs" shall have the meaning set forth in the Operating Agreement.

Affected System:

"Affected System" shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the

Transmission System.

Affected System Operator:

"Affected System Operator" shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

"Agreements" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

All-in-One Plan:

"All-in-One Plan" shall have the meaning set forth in the Operating Agreement.

Ambient-Adjusted Rating:

"Ambient-Adjusted Rating" (AAR) shall mean a Transmission Facility Rating that:

(a) Applies to a time period of not greater than one hour.
(b) Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.
(c) Reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently.
(d) Is evaluated at least each hour, if not more frequently.

Ancillary Services:

"Ancillary Services" shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

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

Annual Energy Efficiency Resource:

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

Annual Resource:

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

Annual Resource Price Adder:

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, 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.

Annual Revenue Rate:

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

"Annual Transmission Costs" shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

"Applicable Laws and Regulations" shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

"Applicable Technical Requirements and Standards" shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, "Applicable Technical Requirements and Standards" shall refer to the "PJM Small Generator Interconnection Applicable Technical Requirements and Standards." All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider's internet website.

Applicant:

"Applicant" shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

"Application" shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

"Attachment Facilities" shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

"Attachment H" shall refer collectively to the Attachments to the PJM Tariff with the prefix "H" that set forth, among other things, the Annual Transmission Rates for Network Integration

Transmission Service in the PJM Zones.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

"Authorized Government Agency" means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

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

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

"Balancing Ratio" shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

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

Base Capacity Demand Resource Constraint:

"Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for 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 Installed Reserve Margin 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 Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint 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 forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

"Base Capacity Demand Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when

the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

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

Base Capacity Resource:

"Base Capacity Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

"Base Capacity Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (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 weekly load distribution (based on the Installed Reserve Margin study and 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 Installed Reserve Margin 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. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint

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 [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

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.

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.

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.

Batch Load Economic Load Response Participant Resource:

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

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generation 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 has 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 Generation Capacity Resource; or (ii) in an 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.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

"Business Day" shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

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

Buyer-Side Market Power:

"Buyer-Side Market Power" shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – C - D

Canadian Guaranty:

"Canadian Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

"Capacity Interconnection Rights" shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

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

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.

Capacity Performance Resource:

"Capacity Performance Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

"Capacity Performance Transition Incremental Auction" shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

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

Capacity Resource with State Subsidy:

"Capacity Resource with State Subsidy" shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

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 Tariff, Attachment DD, section 5.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

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.

Capacity Transmission Injection Rights:

"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource or Open-Loop Hybrid Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Charge Mode. Charge Economic Minimum

Megawatts shall be the Economic Maximum for an Energy Storage Resource or Open-Loop Hybrid Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Charge Mode.

Cleared Capacity Resource with State Subsidy:

"Cleared Capacity Resource with State Subsidy" shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Closed-Loop Hybrid Resource:

"Closed-Loop Hybrid Resource" shall mean a Hybrid Resource that does not operate by charging its storage component from the grid.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval

from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

"Collateral" shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. "Collateral" shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

"Collateral Call" shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Co-Located Resource:

"Co-Located Resource" shall mean a component of a Mixed Technology Facility that operates in the capacity, energy, and/or ancillary services market(s) as a separate resource from the other components of such facility.

Commencement Date:

"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The "Committed Offer" shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected

to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

"Completed Application" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Component DER:

"Component DER" shall mean any resource, within the PJM Region, that is located on a distribution system, any subsystem thereof, or behind a customer meter, and is used in a DER Aggregation Resource by a DER Aggregator to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model. A Component DER may not exceed 5 MW.

Composite Energy Offer:

"Composite Energy Offer" for generation resources shall mean the sum (in $/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in $/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

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.

Conditioned State Support:

"Conditioned State Support" shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where "conditioned on clearing in any RPM Auction" refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

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

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

"Construction Service Agreement" shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

"Contingent Facilities" shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

"Continuous Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants or Open-Loop Hybrid Resource operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

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 automatic generation control scheme is applied in order to:

(1) 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);

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

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

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

Control Zone:

"Control Zone" shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

"Controllable A.C. Merchant Transmission Facilities" shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Core LT Needs:

"Core LT Needs" shall have the meaning set forth in the Operating Agreement.

Core Plan:

"Core Plan" shall have the meaning set forth in the Operating Agreement.

Corporate Guaranty:

"Corporate Guaranty" shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

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 Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, "Costs" shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

Credit Affiliate:

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

"Credit Available for Export Transactions" shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for

Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and

the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

Critical Natural Gas Infrastructure:

"Critical Natural Gas Infrastructure" shall mean locations with electrical loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility as defined by NERC/FERC standard(s); and until such NERC/FERC standard(s) is developed, is defined as electric loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility, which if curtailed, will impact the delivery of natural gas to bulk-power system natural gas-fired generation.

Cross-Border:

When used to describe Network Integration Transmission Service, Network External Designated Transmission Service or Point-to-Point Transmission Service, "Cross-Border" shall mean transmission service where the capacity and/or energy is delivered from a resource that is not part of the PJM Transmission System and/or to load that is not part of the PJM Transmission System.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

"Customer Facility" shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

"Customer-Funded Upgrade" shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

"Customer Interconnection Facilities" shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

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

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 Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-Ahead Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

"Deactivation" shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

"Deactivation Avoidable Cost Credit" shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

"Deactivation Avoidable Cost Rate" shall mean the formula rate established pursuant to Tariff, Part V, section 115.

Deactivation Date:

"Deactivation Date" shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

"Decrement Bid" shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, "Default" shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

"Delivering Party" shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

"Delivery Year" shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

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

Demand Resource Factor or DR Factor:

"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

DER Aggregation Resource:

"DER Aggregation Resource" shall be comprised of one or more Component DER. A DER Aggregation Resource is used by a DER Aggregator to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model. A DER Aggregation Resource is capable of satisfying a minimum energy and/or ancillary services market offer of 100 kW. The market participation eligibility of a DER Aggregation Resource shall be determined in accordance with the physical and operational characteristics of the underlying Component DER that comprise the DER Aggregation Resource.

DER Aggregator:

"DER Aggregator" shall mean an entity that is a Market Participant that: (i) uses one or more DER Aggregation Resources to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model; and (ii) has a fully-executed DER Aggregator Participation Service Agreement.

DER Aggregator Participation Model:

"DER Aggregator Participation Model" shall mean the participation model described in Tariff, Attachment K-Appendix, section 1.4B.

DER Capacity Aggregation Resource:

"DER Capacity Aggregation Resource" shall mean one or more DER Aggregation Resource that participates in the Reliability Pricing Model, capable of satisfying a minimum capacity market offer of 100 kW, or is otherwise treated as capacity in PJM's markets, such as through a Fixed Resource Requirement Capacity Plan, for the 2028/2029 Delivery Year and all subsequent Delivery Years.

Designated Agent:

"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the

Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource or Open-Loop Hybrid Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource or Open-Loop Hybrid Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource or Open-Loop Hybrid Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is only injecting megawatts onto the grid).

Discharge Ramp Rate:

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Discharge Mode.

Dispatch Rate:

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

Dispatched Charging Energy:

"Dispatched Charging Energy" shall mean Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants and Open-Loop Hybrid Resource shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

"Dynamic Schedule" shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

"Dynamic Transfer" shall have the same meaning provided in the Operating Agreement.

Definitions – L – M – N

Legacy Policy:

"Legacy Policy" shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

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

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 Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years 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; 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; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly 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 a Monte Carlo model of hourly capacity levels that is consistent with the capacity model 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) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three 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].

Limited Resource Constraint:

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:
"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

"Load Interest" shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource or Open-Loop Hybrid Resource for later resale to end-use load.

Load Serving Entity (LSE):

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

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

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 Reliability Assurance Agreement, Schedule 10.1.

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.

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.

Locational Reliability Charge:

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

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.

Locational UCAP Seller:

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

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Long-Term Regional Transmission Plan:

"Long-Term Regional Transmission Plan" shall have the meaning set forth in the Operating Agreement.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

"Marginal Value" shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

"Market Monitor**"** means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

"Market Monitoring Unit Advisory Committee" or "MMU Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

"Market Participant" shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

"Market Participant Energy Injection" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

"Market Participant Energy Withdrawal" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

"Market Revenue Neutrality Offset" shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

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 Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

"Market Violation" shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

"Material Modification" shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

"Maximum Daily Starts" shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:

"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any

physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, 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 Tariff, Attachment DD, section 5.10(a) 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 Sub-Annual 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 LDA CETL] minus [the Sub-Annual 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.

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, 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 Tariff, Attachment DD, section 5.10(a) 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 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 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.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

"Mixed Technology Facility" shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

"MOPR Floor Offer Price" shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

"Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

"Native Load Customers" shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner's system to meet the reliable electric needs of such customers.

Near-Term Transmission Service:

"Near-Term Transmission Service" shall mean Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date. "Near-Term Transmission Service" includes any Point-To-Point Transmission Service and Network Integration Transmission Service where the start and end date of the designation or request is within the next 10 days.

NERC:

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

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

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.

Net Obligation:

"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III.

Network Load:

"Network Load" shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer's Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving

Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

"Network Operating Agreement" shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

"Network Operating Committee" shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

"Network Resource" shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

"Network Service User" shall mean an entity using Network Transmission Service.

Network Transmission Service:

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

Network Upgrades:

"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direcct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

"Neutral Party" shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

"New Entry Capacity Resource with State Subsidy" shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

"New Services Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

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.

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.

Non-Curtailment Charge:

"Non-Curtailment Charge" shall mean the charge applicable to Demand Resources and Price Responsive Demand as defined in Tariff, Attachment DD, section 10B(b).

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm

Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-PAI Event:

"Non-PAI Event" shall mean, effective for the 2028/2029 Delivery Year and subsequent Delivery Years, any intervals when a Demand Resource is dispatched or when Price Responsive Demand is required to respond and a Performance Assessment Interval is not in effect for such intervals for the same registration.

Non-Performance Charge:

"Non-Performance Charge" shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

"Nonincumbent Developer" shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

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, or electric distribution companies to serve load.

Non-Synchronized Reserve:

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

"Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

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

Normal Minimum Generation:

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

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Obligation:

"Obligation" shall mean all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Tariff, Part II and Tariff, Part III), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for capacity purchases within the PJM capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Offer Data:

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

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.

Office of the Interconnection Control Center:

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

On-Site Generators:

"On-Site Generators" shall mean generation facilities or portions of a generation facility (including Behind The Meter Generation) that (i) are not Generation Capacity Resources, (ii) are not injecting into the grid for the portion of a generation facility that participates as a Demand Resource or as an Economic Load Response Participant unless permitted as an Economic Load Response Regulation Only Participant, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-Time Information System" or "OASIS" shall mean the electronic communication and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Open-Loop Hybrid Resource:

"Open-Loop Hybrid Resource" shall mean a Hybrid Resource with a storage component that operates by charging its storage component from the grid.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve Demand Curve:

"Operating Reserve Demand Curve" shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that

can be used to meet a given reserve requirement.

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy from the external Generation Capacity Resource to loads in the PJM Region in a manner comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

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

OPSI Advisory Committee:

"OPSI Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

"Option to Build" shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

"Optional Interconnection Study" shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

"Optional Interconnection Study Agreement" shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

"Part I" shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

"Part II" shall mean Tariff, Part II, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

"Part III" shall mean Tariff, Part III, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

"Part IV" shall mean Tariff, Part IV, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

"Part V" shall mean Tariff, Part V, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

"Part VI" shall mean Tariff, Part VI, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

"Participant" shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer**.**

Parties:

"Parties" shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-ahead Energy Market 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 day-ahead 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), plus 10% of such costs only for the 2022/2023 Delivery Year, for at least two hours during each four-hour block, where such blocks shall be assumed to be committed 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 committed for such block; and to the extent not committed in any such block in the Day-ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate, plus 10% of such costs only for the 2022/2023 Delivery Year, under the same conditions as described above for the Day-ahead Energy Market.

Peak Market Activity:

"Peak Market Activity" shall mean a measure of exposure for which credit is required, calculated in accordance with Tariff, Attachment Q, section VII.A.

Peak Market Activity Shortfall:

"Peak Market Activity Shortfall" shall mean, for any given week, the amount by which a Participant's current Peak Market Activity exceeds such Participant's Peak Market Activity credit requirement from the prior week.

Peak Market Activity Surplus:

"Peak Market Activity Surplus" shall mean, for any given week, the amount by which a Participant's Peak Market Activity credit requirement from the prior week exceeds such Participant's current Peak Market Activity.

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.

Percentage Internal Resources Required:

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

Performance Assessment Interval:

"Performance Assessment Interval" shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September.

Permissible Technological Advancement:

"Permissible Technological Advancement" shall mean a proposed technological change such as an advancement to turbines, inverters, plant supervisory controls or other similar advancements to the technology proposed in the Interconnection Request that is submitted to the Transmission Provider no later than the return of an executed Facilities Study Agreement (or, if a Facilities Study is not required, prior to the return of an executed Interconnection Service Agreement). Provided such change may not: (i) increase the capability of the Generating Facility as specified in the original Interconnection Request; (ii) represent a different fuel type from the original Interconnection Request; or (iii) cause any material adverse impact(s) on the Transmission System with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response. If the proposed technological advancement is a Permissible Technological Advancement, no additional study will be necessary and the proposed technological advancement will not be considered a Material Modification.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

"PJM Administrative Service" shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Area Relevant State Entities Committee:

"PJM Area Relevant States Entities Committee" shall have the meaning set forth in the Operating Agreement.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

"PJM Control Area" shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

"PJM Entities" shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM's officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

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

PJM Interchange Energy Market:

"PJM Interchange Energy Market" shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

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

PJM Interchange Import:

"PJM Interchange Import" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the interval scheduled deliveries of

Spot Market Energy to an External Market Buyer; or (d) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Liaison:

"PJM Liaison" shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

"PJM Management" shall mean the officers, executives, supervisors and employee managers of PJM.

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 and the PJM Interchange Energy Market.

PJM Markets:

"PJM Markets" shall mean the PJM Interchange Energy Market, capacity markets, including the RPM auctions, and any other market operated by PJM, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions, Financial Transmission Rights transactions, or transactions in any other market operated under the Agreements within the PJM Region, wherein Market Participants may incur Obligations to PJM and/or PJMSettlement.

PJM Market Rules:

"PJM Market Rules" shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

"PJM Net Assets**"** shall mean the total assets per PJM's consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

"PJM Region" shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:
"PJM Regional Practices Document" shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

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

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 Tariff, Attachment DD, section 5.

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.

PJMSettlement:

"PJM Settlement" or "PJM Settlement, Inc." shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operaitng Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T.," "OATT," or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

"Plan" shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

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

Planned External Generation Capacity Resource:

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

Planned Generation Capacity Resource:

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

Planning Period:

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

Planning Period Balance:

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

Planning Period Quarter:

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

Point(s) of Delivery:

"Point(s) of Delivery" shall mean the point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

"Point of Interconnection" shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

"Point(s) of Receipt" shall mean point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

"Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

"Power Purchaser" shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

"PRD Curve" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Provider:

"PRD Provider" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Reservation Price:

"PRD Reservation" Price shall have the meaning provided in the Reliability Assurance Agreement.

PRD Substation:

"PRD Substation" shall have the meaning provided in the Reliability Assurance Agreement.

Pre-Confirmed Application:

"Pre-Confirmed Application" shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

"Pre-Emergency Load Response Program" shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Pre-Expansion PJM Zones:

"Pre-Expansion PJM Zones" shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC ("MAIT") (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

"Price Responsive Demand" shall have the meaning provided in the Reliability Assurance Agreement.

Primary Reserve:

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Alert

"Primary Reserve Alert" shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

"Primary Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Principal:

"Principal" shall mean (i) all natural persons who Control Corporate Level Strategy for the Participant, which shall include a chief executive officer, managing member (or equivalent positions regardless of title) and members of a board of directors or board of managers; (ii) the chief legal officer or general counsel (or equivalent position regardless of title); (iii) the natural person who Controls the financial affairs and investments of the Participant, which shall include a chief financial officer (or equivalent position regardless of title); (iv) the natural person who Controls the Participant's management of commodity and derivatives market risks, which shall include a chief risk officer (or equivalent position regardless of title); (v) the natural person who

Controls the Participant's transactions in the applicable PJM Markets (regardless of title); and (vi) all Beneficial Owners.

"Control," as that term is used in this definition, refers to possession of the power to direct the management or policies of an entity.

"Corporate Level Strategy," as that term is used in this definition, refers to the highest-level strategy of an entity, focused on the entity's overall direction rather than the day-to-day operations of the entity.

"Beneficial Owner," as that term is used in this definition, means a natural person who, directly or indirectly, alone or together with such person's Family Members, owns, controls, or holds with power to vote 10 percent or more of the outstanding securities of the Participant.

"Family Member," as that term is used in this definition of "Beneficial Owner," means a spouse, domestic partner, parent, child, or sibling.

For purposes of trusts with, directly or indirectly, 10 percent or more of the outstanding securities of the Participant as described above, the following are Beneficial Owners: (a) a natural person trustee; (b) a natural person with the authority to dispose of the trust assets; (c) a natural person grantor or settlor who has the right to revoke the trust or otherwise withdraw the assets of the trust; and (d) a natural person beneficiary who is the sole permissible recipient of income and principal from the trust or has the right to demand a distribution of or withdraw substantially all of the assets from the trust.

If, due to the Participant's business enterprise, structure or otherwise, a function described in clauses (i) through (v) above is performed by a natural person or entity separate from the Participant (such as a risk management department in an affiliate, or a director or manager at an entity that controls or invests in the Participant), then for that Participant the term Principal shall mean that natural person, or the senior officer or manager of that entity, that performs such function.

Prior CIL Exception External Resource:

"Prior CIL Exception External Resource" shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

"Project Financing" shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

"Project Finance Entity" shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

Projected EAS Dispatch:

"Projected EAS Dispatch" shall mean, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource's offer and operating parameters. For combustion turbine units only, the cost-based energy offer will include a 10 percent adder only for the 2022/2023 Delivery Year.

Projected PJM Market Revenues:

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

Proportional Multi-Driver Project:

"Proportional Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Provisional Interconnection Service:

"Provisional Interconnection Service" shall mean interconnection service provided by Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interconnection Service Agreement and, if applicable, the Tariff.

Pseudo-Tie:

"Pseudo-Tie" shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

"Public Policy Objectives" shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

"Public Policy Requirements" shall have the same meaning provided in the Operating Agreement.

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.

Queue Position:

"Queue Position" shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

Definitions – R - S

Ramping Capability:

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

Real-time Congestion Price:

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Offer:

"Real-time Offer" shall mean a new offer or an update to a Market Seller's existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Settlement Interval:

"Real-time Settlement Interval" shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

"Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/ MWh.

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and

decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM 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, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

"Regional Transmission Enhancements" shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that 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 constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

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.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

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

Schedule of Work:

"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Seasonal Facility Rating:

"Seasonal Facility Rating" shall mean a Transmission Facility Rating that:

(a) Applies to a specified season, where seasons are defined by the Office of the Interconnection to include not fewer than four seasons in each year, and to reasonably reflect portions of the year where expected high temperatures are relatively consistent.

(b) Reflects an up-to-date forecast of ambient air temperature across the relevant season over which the rating applies.

(c) Is evaluated annually, if not more frequently, for each season in the future for which Transmission Service can be requested

Secondary Reserve:

"Secondary Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes (less the capability of such resources to provide Primary Reserve), from the request of the Office of the Interconnection, regardless of whether the equipment providing the reserve is electrically synchronized to the Transmission System or not.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

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

Security:

"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

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.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "vertically integrated utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "public power entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

"Self-Supply Seller" shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where "vertically integrated utility" means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and "public power entity" means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

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

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

"Short-term Project" shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, 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.

Short-Term Resource Procurement Target Applicable Share:

"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (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.

Site:

"Site" shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

"Small Commercial Customer," as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start Fuel:

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours)

Start-Up Costs:

"Start-Up Costs" shall consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units): Start-Up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.

For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-Up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

"State Commission**"** shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

"State Subsidy" shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction,

development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State Agreement Process:

"State Agreement Process" shall have the meaning as set forth in Order No. 1920, *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 89 FR 49280 (June 11, 2024), 187 FERC ¶ 61,068, P 45 (2024).

State Cost Assignment Agreement:

"State Cost Assignment Agreement" shall mean an agreement among entities legally authorized to enter into such an agreement to assign costs of a Required Transmission Enhancement and submitted to the Transmission Owners Agreement Administrative Committee pursuant to Tariff, Schedule 12, section (b)(xix)(E).

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in the storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or Hybrid Resource using minimum and maximum discharge (and,

as applicable, charge) limits, changes in operating mode (as applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-Annual Resource Constraint:

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

"Sub-Annual 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 for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource 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 Sub-Annual 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].

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within

the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the

curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

Definitions – T – U - V

Tangible Net Worth:

"Tangible Net Worth" shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

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

Third-Party Sale:

"Third-Party Sale" shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

"Tie Line" shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the

Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

"Total Net Obligation" shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

"Total Net Sell Position" shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Trade Reference:

"Trade Reference" shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement,

Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

"Transmission Constraint Penalty Factor" shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

"Transmission Customer" shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

"Transmission Facilities" shall have the meaning set forth in the Operating Agreement.

Transmission Facility Rating:

"Transmission Facility Rating" shall mean the maximum transfer capability, or the maximum or minimum voltage, current, frequency, or real or reactive power flow, through a Transmission Facility that does not violate the applicable rating of relevant transmission equipment. Transmission Facility Ratings are computed in accordance with a written Transmission Facility Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers. Transmission Facility Ratings also encompass AARs, AAR Exceptions, and Temporary Conditional Transmission Facility Ratings.

Transmission Forced Outage:

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Injection Rights:

"Transmission Injection Rights" shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

"Transmission Interconnection Customer" shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

"Transmission Interconnection Facilities Study" shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

"Transmission Interconnection Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

"Transmission Interconnection Request" shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

"Transmission Owner Attachment Facilities" shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner's side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

"Transmission Owner Interconnection Facilities" shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner's side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

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

Unsecured Credit:

"Unsecured Credit" shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

"Unsecured Credit Allowance" shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: "Working Credit Limit."

Updated VRR Curve:

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

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 and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

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 and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

"Upgrade Construction Service Agreement" shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

"Upgrade Customer" shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

"Upgrade Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

"Upgrade-Related Rights" shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

"Upgrade Request" shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

"Up-to Congestion Counterflow Transaction" shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

"Up-to Congestion Historical Month" shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an "Up-to Congestion Prevailing Flow Transaction" if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

"Up-to Congestion Reference Price" for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30^{th} percentile
For Up-to Congestion Counterflow Transactions when bid: 20^{th} percentile
For Up-to Congestion Counterflow Transactions when cleared: 5^{th} percentile

Up-to Congestion Transaction:

"Up-to Congestion Transaction" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

"Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

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 Tariff, Attachment DD, section 5.

Virtual Credit Exposure:
"Virtual Credit Exposure" shall mean the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

"Virtual Transaction Screening" shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

"Virtual Transactions Net Activity" shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

"Voltage Reduction Action" shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

"Voltage Reduction Alert" shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

"Voltage Reduction Warning" shall mean a notification from PJM to warn Members that PJM's available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

Voluntary Funding Agreement:

"Voluntary Funding Agreement" shall mean an agreement among entities legally authorized to enter into such an agreement to assign the costs of a Required Transmission Enhancement and

submitted to the Transmission Owners Agreement Administrative Committee pursuant to Tariff, Schedule 12, section (b)(xix)(D).

Voluntary Funding Entity:

"Voluntary Funding Entity" shall have the meaning set forth in the Operating Agreement.

SCHEDULE 12
Transmission Enhancement Charges

(a) Establishment of Transmission Enhancement Charges.

(i) Establishment of Transmission Enhancement Charges by Transmission Owners and Entities That Will Become Transmission Owners. One or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements by (1) the Regional Transmission Expansion Plan periodically developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") (collectively, for purposes of this Schedule 12 only, "Regional Transmission Expansion Plan"). Operating Agreement, Schedule 6, section 1.7 recognizes that Transmission Owners, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Required Transmission Enhancements and obligates PJMSettlement to collect on behalf of Transmission Owner(s) any charges established by Transmission Owners to recover the costs of Required Transmission Enhancements. If a Transmission Owner is designated by the Regional Transmission Expansion Plan to construct and own and/or finance a Required Transmission Enhancement, such Transmission Owner may choose any of the following cost recovery mechanisms, subject to the crediting procedures set forth in section (e) below:

(1) Decline to seek to recover the costs of Required Transmission Enhancements from customers until such time as it makes a filing pursuant to Section 205 of the Federal Power Act to revise its Network Integration Transmission Service rates;

(2) Make a filing pursuant Section 205 of the Federal Power Act and the FERC's rules and regulations to establish the revenue requirement with respect to a Required Transmission Enhancement, without filing to revise its rates for Network Integration Transmission Service generally; or

(3) Establish the revenue requirement with respect to a Required Transmission Enhancement through the operation of a formula rate in effect applicable to its rates for Network Integration Transmission Service.

A charge established to recover the revenue requirement with respect to a Required Transmission Enhancement is hereafter referred to as a "Transmission Enhancement Charge." Transmission Enhancement Charges of one or more Transmission Owners for Required Transmission Enhancements shall be established in accordance with this Schedule 12.

(ii) Establishment of Transmission Enhancement Charges With Respect to Required Transmission Enhancements Constructed by Entities in Another Region. The revenue requirement with respect to a Required Transmission Enhancement constructed pursuant to an Appendix B Agreement in another region by an entity designated by such other region shall be governed by the tariffs or agreements in effect in such region. Transmission Enhancement Charges to recover the costs of such Required Transmission Enhancement for which PJM is

responsible shall be determined in accordance with this Schedule 12. Other than with respect to a Required Transmission Enhancement constructed pursuant to an Appendix B Agreement, no PJM Network or Transmission Customer will bear cost responsibility for any required transmission upgrades in another region as a consequence of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan.

(iii) Transmission Facilities Not Eligible for Cost Responsibility Assignment. Any alternating current ("A.C.") facilities or direct current ("D.C.") facilities that are Attachment Facilities, Local Upgrades, Merchant Network Upgrades, Merchant Transmission Facilities, Network Upgrades, Supplemental Projects, or any other Transmission Facilities that operate or are planned to be operated in a manner that requires customers to subscribe to transmission service over such facilities or to a portion of the electric capability of such facilities shall not be eligible for cost responsibility assignment pursuant to this Schedule 12.

(iv) Entities Not Yet Eligible to Become Transmission Owners. For purposes of this Schedule 12 only, the term, "Transmission Owner," shall include any entity that undertakes to construct and own and/or finance a Required Transmission Enhancement pursuant to a designation in the Regional Transmission Expansion Plan to construct and own and/or finance such Required Transmission Enhancement, even if such entity is not yet eligible to become a party to the Consolidated Transmission Owners Agreement. Nothing in the PJM Tariff nor the Consolidated Transmission Owners Agreement shall prevent an entity that undertakes to construct and own and/or finance a Required Transmission Enhancement pursuant to a designation in the Regional Transmission Expansion Plan to construct and own and/or finance such Required Transmission Enhancement from recovering the costs of such Required Transmission Enhancement through this Schedule 12.

(v) Effective Date. The assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider prior to February 1, 2013, or (2) applicable to Required Transmission Enhancements approved by the PJM Board pursuant to Operating Agreement, section 1.6 prior to February 1, 2013 are set forth in Tariff, Schedule 12-Appendix. Except as specifically set forth herein, nothing in this Schedule 12 shall change the assignment of cost responsibility or classification of Required Transmission Enhancements included in Tariff, Schedule 12-Appendix. The assignment of cost responsibility or classification of all other Required Transmission Enhancements shall be set forth in Tariff, Schedule 12-Appendix A.

(b) Designation of Customers Subject to Transmission Enhancement Charges.

(i) Regional Facilities and Necessary Lower Voltage Facilities. Transmission Provider shall assign cost responsibility on a region-wide basis for Required Transmission Enhancements included in the Regional Transmission Expansion Plan that (1) (a) are A.C. facilities that operate at or above 500 kV; (b) constitute a single Required Transmission Enhancement comprising two A.C. circuits operating at or above 345 kV and below 500 kV, where both circuits originate from a single substation or switching station at one end and terminate at a single substation or switching station at the other end, regardless of whether or not

the two circuits are routed in the same right-of-way ("Double-circuit 345 kV Required Transmission Enhancement"); (c) are A.C. or D.C. shunt reactive resources (such as capacitors, static var compensators, static synchronous condenser (STATCON), synchronous condensers, inductors, other shunt devices, or their equivalent) connected to a Transmission Facility described in clause (a) or (b) of this subsection, or (d) are D.C. facilities meeting the criteria set forth in subsection (b)(i)(D) (collectively, "Regional Facilities"), or (2) new A.C. Transmission Facilities or expansions or enhancements to existing Transmission Facilities that operate below 500 kV (or 345 kV in the case of a Regional Facility described in clause (1)(b) of this subsection) or new D.C. Transmission Facilities that do not meet the criteria of subsection (b)(i)(D) that must be constructed or strengthened to support new Regional Facilities, based on the planning criteria used by the Transmission Provider in developing the applicable Regional Transmission Expansion Plan ("Necessary Lower Voltage Facilities") as follows:

(A) Cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities shall be allocated among Responsible Customers as defined in this Schedule 12 as follows:

(1) Fifty percent (50%) shall be assigned annually on a load-ratio share basis as follows:

(a) With respect to each Zone, using, consistent with Tariff, Part III, section 34.1, the applicable zonal loads at the time of such Zone's annual peak load from the 12-month period ending October 31 preceding the calendar year for which the annual cost responsibility allocation is determined; and

(b) With respect to Merchant Transmission Facilities, (1) for the calendar year following the year in which it initiates operation, the actually awarded Firm Transmission Withdrawal Rights associated with its existing Merchant Transmission Facility; and (2) for all subsequent calendar years, the annual peak load of the Merchant Transmission Facility (not to exceed its actual Firm Transmission Withdrawal Rights) from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility allocation is determined.

(2) Fifty percent (50%) shall be assigned as follows:

(a) In the case of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to address one or more reliability violations or to address operational adequacy and performance issues (collectively, "Reliability Project"), in accordance with the distribution factor ("DFAX") analysis described in subsection (b)(iii) or the analysis applicable to Regional Facilities that address stability issues described in subsection (b)(xviii) of this Schedule 12 as applicable; and

(b) In the case of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to relieve one or more economic constraints as described in Operating Agreement, Schedule 6, section 1.5.7(b)(iii) ("Economic Project"), in accordance with the methodology described in subsection (b)(v) of this Schedule 12.

(B) (1) Except for transformers that are an integral component of a Regional Facility, transformers connected to Lower Voltage Facilities, as defined in section (b)(ii) of this Schedule 12, shall not be considered Regional Facilities or Necessary Lower Voltage Facilities; and (2) Transmission Facilities that are not Regional Facilities and deliver energy from a Regional Facility to load shall not be considered Necessary Lower Voltage Facilities.

(C) With respect Required Transmission Enhancements that qualify as Regional Facilities under subsection (b)(i)(1)(b) or subsection (b)(i)(D)(2) of this Schedule 12:

(1) where the Required Transmission Enhancement includes both new Transmission Facilities and pre-existing Transmission Facilities, cost responsibility under this section (b)(i) shall apply only to the cost of the new Transmission Facilities plus the original cost less accumulated depreciation of pre-existing Transmission Facilities that are included in Tariff, Schedule 12-Appendix or Tariff, Schedule 12-Appendix A;

(2) cost responsibility shall be assigned under this section (b)(i) only after the Required Transmission Enhancement goes into service as a Double-circuit 345 kV Required Transmission Enhancement or a Double-circuit D.C. Required Transmission Enhancement; and

(3) cost responsibility shall be assigned under this section (b)(i) for any CWIP permitted to be recovered before the Required Transmission Enhancement goes into service only after such Transmission Facilities are approved in a Regional Transmission Expansion Plan as a Double-circuit 345 kV Required Transmission Enhancement or a Double-circuit D.C. Required Transmission Enhancement.

(D) A Required Transmission Enhancement included in the Regional Transmission Expansion Plan that is a D.C. facility, consisting of D.C. lines (i.e., wires or cables) and A.C./D.C. converters, shall be a Regional Facility only if:

(1) such D.C. facility comprises two poles and operates at a voltage of ±433 kV D.C. or above; or

(2) such D.C. Facility constitutes a single Required Transmission Enhancement comprising two D.C. circuits where (i) both circuits originate from a single substation or switching station at one end and terminate at a single substation or switching station at the other end, regardless of whether or not both circuits are routed in the same right-of-way, and (ii) each such circuit consists of two poles and operates at a voltage of ±298 kV D.C or above ("Double-circuit D.C. Required Transmission Enhancement").

(ii) Lower Voltage Facilities. Transmission Provider shall assign cost responsibility for Required Transmission Enhancements that (a) are not Regional Facilities; and (b) are not "Necessary Lower Voltage Facilities" as defined in section(b)(i) of this Schedule 12 (collectively "Lower Voltage Facilities"), as follows:

(A) If the Lower Voltage Facility is a Reliability Project, Transmission Provider shall use the DFAX analysis described in subsection (b)(iii) or the analysis applicable to

Regional Facilities that address stability issues described in subsection (b)(xviii) of this Schedule 12 as applicable; and

(B) If the Lower Voltage Facility is an Economic Project, Transmission Provider shall use the methodology described in subsection (b)(v) of this Schedule 12.

(iii) DFAX Analysis for Reliability Projects.

(A) For purposes of the assignment of cost responsibility for Reliability Projects under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of this Schedule 12, the Transmission Provider, based on a computer model of the electric network and using power flow modeling software, shall calculate distribution factors, represented as decimal values or percentages, which express the portions of a transfer of energy from a defined source to a defined sink that will flow across a particular transmission facility or group of transmission facilities. These distribution factors represent a measure of the use by the load of each Zone or Merchant Transmission Facility (collectively, "Responsible Zone") of the Required Transmission Enhancement, as determined by a power flow analysis. In general, a distribution factor can be represented as:

Distribution Factor = (After-shift power flow – pre-shift power flow) / Total amount of power shifted

Total amount of power shifted = Modeled incremental megawatt transfer to a given Load Deliverability Area or Merchant Transmission Facility

Pre-shift power flow = Megawatt flow over the Required Transmission Enhancement before the incremental megawatt transfer

After-shift power flow = Megawatt flow over the Required Transmission Enhancement after the incremental megawatt transfer

When calculating such distribution factors:

(1) All distribution factors are calculated with respect to the Required Transmission Enhancement subject to cost allocation under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of this Schedule 12.

(2) The calculation of distribution factors shall be determined using linear matrix algebra, such that distribution factors represent the ratio of (i) a change in megawatt flow on a Required Transmission Enhancement to (ii) a change in megawatts transferred to aggregate load within a Zone or, in the case of a Merchant Transmission Facility, the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

(3) With respect to a Merchant Transmission Facility, zonal peak load shall mean (i) the existing Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated, if the Merchant Transmission Facility is in service, or (ii) for a

Merchant Transmission Facility that is not yet in service, the planned Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated as identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility.

(4) In the DFAX analysis, when Transmission Provider models a transfer from generation to all load within an individual Zone, Transmission Provider shall model the transfer to the Zone as a whole (not on a bus-by-bus basis).

(5) In the DFAX analysis, Transmission Provider shall model generation both external and internal to individual Responsible Zones to reflect (a) the boundaries of Locational Deliverability Areas ("LDAs"), and (b) limitations with respect to the reliability objective for moving generation capacity across the transmission system. Transmission Provider shall adopt the Capacity Emergency Transfer Objective ("CETO"), associated with that LDA and calculated for the applicable planning year to be the transfer limitation into the LDA. In modeling the system generation and load, Transmission Provider shall assume that the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA shall equal the ratio of (i) the CETO associated within that LDA (or generation internal with the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the distribution factor, Transmission Provider shall distribute these amounts of external/internal generation among all generation in the PJM Region external to/internal within the LDA, respectively, in proportion to their capacity. For Responsible Zones that are located within LDAs that are also entirely contained in other larger LDAs, the modeling approach and distribution factor calculations shall be repeated for such Responsible Zones for each LDA. The lowest distribution factor derived from these calculations shall be applied to the Responsible Zone in the calculation of the use of the Required Transmission Enhancement.

(B) The DFAX analysis will be performed in accordance with the following steps:

(1) Transmission Provider shall calculate a distribution factor and a direction of use for each Responsible Zone by modeling a transfer from all generation in the PJM Region to each Responsible Zone. To establish the use by a Responsible Zone, in megawatts, of a Required Transmission Enhancement, the distribution factor of a Required Transmission Enhancement associated with the resulting transfer modeled by the Transmission Provider to each Responsible Zone shall be multiplied by the Responsible Zone's peak load.

(2) The Transmission Provider shall separately determine the relative use of the Required Transmission Enhancement by each Responsible Zone in each direction by dividing the megawatts of use by each Responsible Zone determined in section (iii)(B)(1) above by the total use of all Responsible Zones using the Required Transmission Enhancement in the same direction of use.

(3) Transmission Provider shall determine the direction of use percentage of the Required Transmission Enhancement in each direction using a production cost analysis to determine the total use, in megawatt-hours, of the Required Transmission Enhancement by all Zones and Merchant Transmission Facilities in each direction over the course of a year. The Transmission Provider shall calculate the percentage use in each direction by dividing the megawatt-hours of use in each direction by total use in megawatt-hours in both directions of use.

(4) The Transmission Provider shall multiply the relative use by each Responsible Zone of the Required Transmission Enhancement in each direction of use determined in section (iii)(B)(2) above, by the applicable direction of use percentage determined in section (iii)(B)(3) above.

(5) The products of the calculation performed in section (iii)(B)(4) above, shall determine the relative allocation to each Responsible Zone of cost responsibility for the Required Transmission Enhancement.

(C) In the DFAX analysis, the Zones of Public Service Electric and Gas Company and Rockland Electric Company will be treated as one Zone unless and until Rockland Electric Company elects to be treated as a separate Zone in accordance with the terms of the Settlement Agreement And Offer Of Partial Settlement approved by FERC in Docket Nos. ER06-456-000, et al.

(D) Transmission Provider shall round cost responsibility assignments determined using the DFAX analysis described in subsection (b)(iii) of this Schedule 12 to the nearest one-hundredth of one percent.

(E) Transmission Provider shall not account for the ability to adjust use of phase angle regulators ("PARs") in the DFAX analysis described in subsection (b)(iii) of this Schedule 12. In the DFAX analysis, all PAR angles shall be fixed at their base case settings.

(F) In the DFAX analysis, if the Required Transmission Enhancement is a D.C. facility, the Transmission Provider shall determine cost responsibility assignment as follows:

(1) The Required Transmission Enhancement shall be replaced in the model with a comparable proxy A.C. facility, the impedance of which shall be calculated based on the length of the D.C. facility that was removed from the model multiplied by an approximate per unit/mile impedance value for the proxy A.C. facility.

(2) Where a D.C. facility is an integral part of a Required Transmission Enhancement that also includes A.C. facilities, the methodology described in subsection (b)(iii)(F)(1) above shall be used only for the D.C. facility segment of such Required Transmission Enhancement.

(3) A D.C. facility used to control flow over portions of the Transmission System shall be modeled with a zero impedance and no control shall be applied.

(G) If Transmission Provider determines in its reasonable engineering judgment that, as a result of applying the provisions in section (b)(iii) of this Schedule 12, the DFAX analysis cannot be performed or that the results of such DFAX analysis are objectively unreasonable, the Transmission Provider may use an appropriate substitute proxy for the Required Transmission Enhancement in conducting the DFAX analysis. If a proxy is used that is not specified in this Schedule 12, Transmission Provider shall state in a written report (a) the reasons why it determined the DFAX analysis could not be performed or that the results of the DFAX analysis were objectively unreasonable; (b) why the substitute proxy produced objectively reasonable results; and (3) a recommendation as to what changes, if any, should be considered in conducting the DFAX analysis.

(H) The Transmission Provider shall make a preliminary cost responsibility determination for each Required Transmission Enhancement subject to section (b)(iii) of this Schedule 12 at the time such Required Transmission Enhancement is included in the Regional Transmission Expansion Plan.

(1) When CWIP in connection with a Required Transmission Enhancement subject to this section (b)(iii) of this Schedule 12 is entitled to be recovered, the preliminary determination of cost responsibility made at the time that the Required Transmission Enhancement was included in the Regional Transmission Expansion Plan shall be used to assign cost responsibility for such CWIP and such cost responsibility shall remain unchanged until the date the Required Transmission Enhancement goes into service. Once a Required Transmission Enhancement has gone into service, the updated cost responsibility determination provided for in subsection (b)(iii)(H)(2) below shall apply.

(2) Beginning with the calendar year in which a Required Transmission Enhancement is scheduled to enter service, and thereafter annually at the beginning of each calendar year, the Transmission Provider shall update the preliminary cost responsibility determination for each Required Transmission Enhancement using the values and inputs used in the base case of the most recent Regional Transmission Expansion Plan approved by the PJM Board prior to the date of the update. All values and inputs used in the calculation of the distribution factor in a determination of cost responsibility shall be the same values and inputs as used in the base case of the most recent Regional Transmission Expansion Plan approved by the PJM Board prior to the determination of cost responsibility.

(iv) Spare Parts, Replacement Equipment And Circuit Breakers. Transmission Provider shall assign cost responsibility for spare parts, replacement equipment, and circuit breakers and associated equipment, included in the Regional Transmission Expansion Plan as follows:

(A) Spare parts that are part of the design specifications of a Required Transmission Enhancement at the time such Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required

Transmission Enhancement for the purpose of applying the cost threshold described in subsection (b)(vi) of this Schedule 12 and cost responsibility for such spare parts shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for spare parts independently included the Regional Transmission Expansion Plan and not a part of the design specifications of a Required Transmission Enhancement as described above in this subsection shall be assigned to the Zone of the owner of the spare part, if the owner of the spare part is a Transmission Owner listed in Tariff, Attachment J. If the owner of the spare part is not a Transmission Owner listed in Tariff, Attachment J, cost responsibility shall be assigned on a pro rata basis to the zones that bear cost responsibility for the owner's Required Transmission Enhancements.

(B) Replacement equipment that is part of the design specifications of a Required Transmission Enhancement at the time the Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required Transmission Enhancement for the purpose of applying the cost threshold described in section (b)(vi) of this Schedule 12 and cost responsibility for such replacement equipment shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for Required Transmission Enhancement replacement equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a Required Transmission Enhancement as described above in this subsection, shall be assigned to the same Zones and/or Merchant Transmission Facilities and in the same proportions as the then-existing assignments of cost responsibility for the facilities that the replacement equipment is replacing.

(C) Circuit breakers and associated equipment that are part of the design specifications of a Required Transmission Enhancement at the time the Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required Transmission Enhancement for the purpose of applying the cost threshold described in subsection (b)(vi) of this Schedule 12 and cost responsibility for such circuit breakers and associated equipment shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for circuit breakers and associated equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Required Transmission Enhancement as described above in this subsection, shall be assigned to the Zone of the owner of the circuit breaker and associated equipment if the owner of the circuit breaker is a Transmission Owner listed in Tariff, Attachment J. If the owner of the circuit breaker is not a Transmission Owner listed in Tariff, Attachment J, cost responsibility shall be assigned on a pro rata basis to the zones that bear cost responsibility for the owner's Required Transmission Enhancements.

(v) Economic Projects. Transmission Provider shall assign (i) fifty percent (50%) of cost responsibility for Economic Projects that are Regional Facilities; and (ii) full cost responsibility for Economic Projects that are Lower Voltage Facilities; as follows:

(A) Transmission Provider shall assign cost responsibility for Economic Projects that are accelerations of Reliability Projects as described in Operating Agreement, Schedule 6, section 1.5.7(b)(i) ("Acceleration Projects") by performing and comparing (1) a DFAX analysis consistent with the methodology described in subsection (b)(iii) of this Schedule

12, and (2) a methodology that is intended to act as a proxy for expected economic benefits from reduced Locational Marginal Prices ("LMP Benefit") over the period that the reliability-based enhancement or expansion is to be accelerated ("LMP Benefits Methodology"). The LMP Benefits Methodology shall determine cost responsibility assignment percentages to Zones and Merchant Transmission Facilities in the following manner. The LMP Benefit to a Zone shall be deemed to be equal to the reduction in Locational Marginal Price payments made by Load Serving Entities as a result of the Acceleration Project assuming the customers purchase all energy needs from the PJM Interchange Energy Market, and LMP Benefits so calculated shall be converted into percentage cost responsibility assignments for the affected Zones. The LMP Benefits Methodology shall not incorporate the financial effects of allocations of Auction Revenue Rights or Financial Transmission Rights. The LMP Benefit to a Merchant Transmission Facility shall be deemed to be equal to the proportionate share of assigned cost responsibility using the DFAX analysis and the assignments of cost responsibility to other Zones in the LMP Benefits Methodology shall be proportionately adjusted, as necessary, to reflect this treatment of Merchant Transmission Facilities to ensure that the total allocation for any economic-based Required Transmission Enhancement equals one hundred percent. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and the LMP Benefits Methodology, the results do not indicate at least a ten percentage point cost responsibility assignment differential between the two methods for any Zone, cost responsibility for the Acceleration Project shall be assigned using the DFAX analysis. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and LMP Benefits Methodology, the results indicate at least a ten percentage point cost responsibility assignment differential between the DFAX analysis and the LMP Benefits Methodology for any Zone, cost responsibility for the Acceleration Project for the period of time the Reliability Project is accelerated (i.e. the period between the date the Reliability Project actually goes into service and the date the Reliability Project originally was scheduled to go in service in the PJM Board approved Regional Transmission Expansion Plan) shall be assigned using the LMP Benefits Methodology. For all periods other than the period of time the Reliability Project is accelerated, cost responsibility for such an Acceleration Project shall be assigned in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility of Regional Facility Reliability Projects or Lower Voltage Facility Reliability Projects, as applicable.

(B) Transmission Provider shall assign cost responsibility for Economic Projects that are modifications to Reliability Projects as described in Operating Agreement, Schedule 6, section 1.5.7(b)(ii) in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility of Regional Facility Reliability Projects or Lower Voltage Facility Reliability Projects, as applicable.

(C) Transmission Provider shall assign cost responsibility for Economic Projects that are new enhancements or expansions that could relieve one or more economic constraints as described in Operating Agreement, Schedule 6, section 1.5.7(b)(iii) to the Zones that show a decrease in the net present value of the Changes in Load Energy Payment. The Change in Load Energy Payment for each year shall be determined using the methodology set forth in Operating Agreement, Schedule 6, section 1.5.7(d) for the period specified in that

section. Cost responsibility shall be assigned based on each Zone's pro rata share of the sum of the net present values of the Changes in Load Energy Payment only of the Zones in which the net present value of the Changes in Load Energy Payment shows a decrease.

(vi) Required Transmission Enhancements Costing Less Than $5 Million. Notwithstanding sections (b)(i), (b)(ii), (b)(iv), (b)(v), and (b)(~~v~~xix) of this Schedule 12, cost responsibility for a Required Transmission Enhancement for which the good faith estimate of the cost of the Required Transmission Enhancement (a) prepared in connection with the development of the Regional Transmission Expansion Plan and (b) provided to the PJM Board at the time the Required Transmission Enhancement is included for the first time in the Regional Transmission Expansion Plan, does not equal or exceed $5 million shall be assigned to the Zone where the Required Transmission Enhancement is to be located. The determination of whether the estimated cost of a Required Transmission Enhancement does not equal or exceed $5 million shall be based solely on such good faith estimate of the cost of the Required Transmission Enhancement regardless of the actual costs incurred. The estimated cost of a Required Transmission Enhancement shall include the aggregate estimated costs of all of the transmission elements approved by the PJM Board at the time such elements are included in the Regional Transmission Expansion Plan that collectively are intended (i) in the case of a Reliability Project, to resolve a specific reliability criteria violation, or (ii) in the case of an Economic Project, provide a specific LMP Benefit. Where a Required Transmission Enhancement subject to this section (b)(vi) consists of a single transmission element or multiple transmission elements that will be located in more than one Zone, each Zone shall be assigned cost responsibility for the transmission elements or portions of the transmission elements located in such Zone. Merchant Transmission Facilities shall not be assigned cost responsibility for a Required Transmission Enhancement subject to this section (b)(vi).

(vii) Modifications of Required Transmission Enhancements. Once a Required Transmission Enhancement is included in the Regional Transmission Expansion Plan, any modification to such Required Transmission Enhancement that subsequently is included in the Regional Transmission Expansion Plan as a separate Reliability or Economic Project shall be considered a separate and distinct Required Transmission Enhancement for purposes of cost responsibility assignment under this Schedule 12. Except as provided in sections (b)(iv) and (b)(xiv) of this Schedule 12, any cost responsibility assignment that has been made for a previously approved Required Transmission Enhancement shall have no impact on the cost responsibility assignment of such modification.

(viii) FERC Filing. Within 30 days of the approval of each Regional Transmission Expansion Plan or an addition to such plan by the PJM Board pursuant to Operating Agreement, Schedule 6, section 1.6, the Transmission Provider shall designate in the Tariff, Schedule 12-Appendix A and in a report filed with the FERC the customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service and Merchant Transmission Facility owners that will be subject to each such Transmission Enhancement Charge ("Responsible Customers") based on the cost responsibility assignments determined pursuant to this Schedule 12. Those customers designated by the Transmission Provider as Responsible Customers shall have 30 days from the date the filing is made with the FERC to seek review of such designation. Such cost responsibility designations shall be the same as those

made for the relevant Regional Facility, Necessary Lower Voltage Facility, or Lower Voltage Facility in the Regional Transmission Expansion Plan.

(ix) Regions With Which PJM Has Entered Into an Agreement Listed in Schedule 12-Appendix B . For purposes of this Schedule 12, where costs of a Required Transmission Enhancement are allocated to a region other than PJM pursuant to an agreement set forth in Tariff, Schedule 12-Appendix B, Responsible Customers for such costs shall be customers in such region. Cost responsibility with respect to the costs of a Required Transmission Enhancements allocated to a region other than PJM shall be allocated within such region in accordance with the applicable tariff or agreement governing the allocation of such costs in such region.

(x) Merchant Transmission Facilities.

(A) For purposes of this Schedule 12, where the Transmission Provider has allocated all or a portion of a Required Transmission Enhancement to a Merchant Transmission Facility, the owner of the Merchant Transmission Facility shall be the Responsible Customer with respect to such Required Transmission Enhancement, and shall pay the Transmission Enhancement Charges associated with the Required Transmission Enhancement.

(B) (1) Transmission Provider shall defer collection of Transmission Enhancement Charges from a Merchant Transmission Facility until the Merchant Transmission Facility goes into commercial operation; provided, however, in the event the commercial operation of a Merchant Transmission Facility is delayed beyond the commercial operation milestone date(s) specified in the Interconnection Service Agreement associated with the Merchant Transmission Facility and the Transmission Provider or Transmission Owner constructing the Required Transmission Enhancement demonstrates that the Merchant Transmission Facility is responsible for such delay, Transmission Provider may begin collecting Transmission Enhancement Charges from the Merchant Transmission Facility prior to the Merchant Transmission Facility going into commercial operation. Transmission Enhancement Charges allocated to a Merchant Transmission Facility for which collection is deferred in accordance with this section (b)(x)(B)(1) shall be recorded in appropriate Transmission Provider accounts for deferred charges and collected in accordance with section (b)(x)(B)(3) below.

(2) Transmission Provider shall base the collection of Transmission Enhancement Charges associated with Required Transmission Enhancements from a Merchant Transmission Facility on the actual Firm Transmission Withdrawal Rights that have been awarded to the Merchant Transmission Facility; provided, however, to the extent that a Merchant Transmission Facility has been awarded less than the amount of Firm Transmission Withdrawal Rights specified in the Interconnection Service Agreement associated with the Merchant Transmission Facility, then Transmission Provider shall record the difference between the amount of Transmission Enhancement Charges collected based on the lesser amount of Firm Transmission Withdrawal Rights and the amount of Transmission Enhancement Charges based on the full amount of Firm Transmission Withdrawal Rights specified in the applicable Interconnection Service Agreement in appropriate accounts for deferred charges and, after the Merchant Transmission Facility has been awarded the full amount of Firm Transmission

Withdrawal Rights specified in the Interconnection Service Agreement, collect such deferred amounts in accordance with section (b)(x)(B)(3) below. Notwithstanding the foregoing, Transmission Provider may collect Transmission Enhancement Charges based on more than a Merchant Transmission Facility's actually awarded Firm Transmission Withdrawal Rights (not to exceed the Firm Transmission Withdrawal Rights specified in the applicable Interconnection Service Agreement) if the Transmission Provider or Transmission Owner demonstrates that the Merchant Transmission Facility is responsible for receiving fewer Firm Transmission Withdrawal Rights than are specified in the applicable Interconnection Service Agreement.

(3) Transmission Provider shall record: (i) in an appropriate deferred asset account, the Transmission Enhancement Charges associated with Required Transmission Enhancements for which collection is deferred in accordance with sections (b)(x)(B)(1) and (b)(x)(B)(2) above; and (ii) in an appropriate deferred liability account, the revenues associated with the Transmission Enhancement Charges that, absent the deferred charges, would have been due to Transmission Owners or to Transmission Owners' customers as directed by the applicable Transmission Owner. At such time as collection of such deferred Transmission Enhancement Charges are permitted in accordance with sections (b)(x)(B)(1) and (b)(x)(B)(2) above, the deferred charges (along with appropriate interest) shall be collected from the Merchant Transmission Facility in equal installments over the twelve months following the commencement of the collection of the deferred charges. Such amounts shall be distributed to Transmission Owners or to Transmission Owners' customers as directed by the applicable Transmission Owner, and the Transmission Provider shall make appropriate adjustments to the deferred asset and liability accounts. Transmission Provider shall not be responsible for distributing revenues associated with deferred Transmission Enhancement Charges unless and until such charges are collected in accordance with this section (b)(x)(B), and uncollected deferred Transmission Enhancement Charges shall not be subject to Default Allocation Assessments to the Members pursuant to Operating Agreement, section 15.2.

(xi) Consolidated Edison Company of New York. (A) Cost responsibility assignments to Consolidated Edison Company of New York for Required Transmission Enhancements pursuant to this Schedule 12 with respect to the Firm Point-To-Point Service Agreements designated as Original Service Agreement No. 1873 and Original Service Agreement No. 1874 accepted by the Commission in Docket No. ER08-858 ("ConEd Service Agreements") shall be in accordance with the terms and conditions of the settlement approved by the FERC in Docket No. ER08-858-000. (B) All cost responsibility assignments for Required Transmission Enhancements pursuant to this Schedule 12 shall be adjusted at the commencement and termination of service under the ConEd Service Agreements to take account of the assignments under subsection (xi)(A) of this section.

(xii) Public Policy Projects.

(A) Transmission Facilities as defined in Consolidated Transmission Owners Agreement, section 1.27 constructed by a Transmission Owner pursuant to a Public Policy Requirement but not included in a Regional Transmission Expansion Plan as a Required Transmission Enhancement, shall be as considered a Supplemental Project.

(B) If a transmission enhancement or expansion is proposed pursuant to Operating Agreement, Schedule 6, section 1.5.9(a) which is not a Supplemental Project ("State Agreement Public Policy Project"), the Transmission Provider shall submit the assignment of costs to Responsible Customers proposed in connection with such State Agreement Public Policy Project to the Transmission Owners Agreement Administrative Committee for consideration and filing pursuant to Consolidated Transmission Owners Agreement, section 7.3 and Tariff, Part I, section 9.1(a). Nothing in this section (b)(xii) shall prevent the Transmission Provider or the state governmental entities proposing such State Agreement Public Policy Project from filing a proposed assignment of costs to Responsible Customers for such project pursuant to Section 206 of the Federal Power Act.

(xiii) Replacement of Transmission Facilities. Unless determined by PJM to be a Required Transmission Enhancement included in a Regional Transmission Expansion Plan, cost responsibility for the replacement of Transmission Facilities, as defined in Consolidated Transmission Owners Agreement, section 1.27, shall be assigned to the Zonal loads and Merchant Transmission Facilities responsible for the costs of the Transmission Facilities being replaced.

(xiv) Multi-Driver Projects.

(A) Assignment of Proportional Multi-Driver Project Costs. The Transmission Provider shall assign cost responsibility for Proportional Multi-Driver Projects in proportion to the relative percentage benefit that each driver of a Proportional Multi-Driver Project addresses, respectively, reliability violations or operational performance ("reliability"), economic constraints ("economic") and/or Public Policy Requirements ("public policy") as follows:

(1) As part of the open planning process provided for in Operating Agreement, Schedule 6, section 1.5.10(h), the Transmission Provider employs the Proportional Method to develop a Proportional Multi-Driver Project, by determining which of the following drivers a Proportional Multi-Driver Project addresses: reliability, economic, or public policy, and the extent to which each such driver contributes to the size, scope, and estimated costs of such Proportional Multi-Driver Project (irrespective of the reliability cost allocation treatment that is otherwise accorded an incremental market efficiency modification thereto pursuant to section (b)(v)(B) of this Schedule 12). The Transmission Provider shall identify the contribution of each driver in terms of a percentage totaling 100 percent for all such drivers at the time that each Proportional Multi-Driver Project is submitted to the PJM Board for approval and included in the Regional Transmission Expansion Plan. The percentage contribution of each driver shall be based on the ratio of the estimated cost of each project that the Multi-Driver Project replaces to the total of the estimated costs of all projects combined into the Multi-Driver Project.

(2) Once a Proportional Multi-Driver Project is approved by the PJM Board, the percentage contributions of each driver shall not be changed unless the PJM Board subsequently approves an upgrade or modification to the Proportional Multi-Driver

Project. In that event, the cost responsibility for the Proportional Multi-Driver Project, including any costs incurred prior to the upgrade or modification, will be determined as if it were a new Proportional Multi-Driver Project, such that the percentage contribution for each driver shall be established anew.

(B) Assignment of Incremental Multi-Driver Project Costs. The Transmission Provider shall assign cost responsibility for Incremental Multi-Driver Projects as defined in Operating Agreement, Schedule 6, section 1.15B using the same methodology described in section (b)(xiv)(A)(1) above treating the estimated cost of modifying the original project as if it were the estimated cost of a separate project included in a Proportional Multi-Driver Project. Any costs that had been expended on the original project prior its designation by Transmission Provider as an Incremental Multi-Driver Project shall be included in the calculation of the Incremental Multi-Driver Project pursuant to this section (b)(xiv)(B).

(C) The Transmission Provider shall separately assign cost responsibility for the costs assigned to each driver pursuant to this section (b)(xiv) in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility for a single driver project of each driver's respective type (reliability, economic or public policy). Except as provided in section (b)(xiv)(D) below, cost responsibility will be assigned based on the final voltage and configuration of the Multi-Driver Project determined in accordance with sections (b)(i), (b)(ii), or (b)(vi) of this Schedule 12.

(D) Notwithstanding the cost assignments that would otherwise be provided for in section (b)(xiv)(C) above, if a Multi-Driver Project includes a public policy driver that is the result of the State Agreement Approach provided for in Operating Agreement, Schedule 6, section 1.5.9 and is a Regional Facility as defined in section (b)(i) of this Schedule 12 and such Multi-Driver Project would not be a Regional Facility but for the inclusion of the public policy driver, then the percentage of costs of such Multi-Driver Project assigned to the non-public policy drivers in accordance with the procedures set forth in in section (b)(i)(A)(1) above shall be twenty percent (20%) and the percentage of costs assigned to the non-public policy drivers of such Multi-Driver Project in accordance section (b)(i)(A)(2) above shall be eighty percent (80%), and not the fifty percent (50%) cost responsibility percentages provided for in section (b)(i)(A)(i) and section (b)(i)(A)(2), respectively, of this Schedule 12.

(xv) ***Reserved.***

(xvi) Required Transmission Enhancements Designed to Address Reliability Violations on Transmission Facilities Operating Below 200 kV. Notwithstanding section (b)(ii), above, cost responsibility for any Required Transmission Enhancements that are included in the Regional Transmission Expansion Plan to address reliability violations on Transmission Facilities that are designed to operate at below 200 kV and, pursuant to Operating Agreement, Schedule 6, section 1.5.8(n), were not included in an Operating Agreement, Schedule 6, section 1.5.8(c) proposal window, shall be assigned to the Responsible Customers in the Zone where the Required Transmission Enhancement is to be located.

(xvii) Required Transmission Enhancements Constructed As Targeted Market Efficiency Projects Under The Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. Coordinated System Plan. Notwithstanding sections (b)(i), (b)(ii), (b)(iv), (b)(v), (b)(vi) and (b)(x)(B)(2) of this Schedule 12, cost responsibility for the costs of a Required Transmission Enhancement that is included in the Regional Transmission Expansion Plan because it is a Targeted Market Efficiency Project ("TMEP") identified in the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. ("PJM-MISO JOA") and assigned to PJM pursuant to PJM-MISO JOA, section 9.4.4.2.5, shall be assigned among Zones and Merchant Transmission Facilities in accordance with this section (b)(xvii). Using the Targeted Market Efficiency Project study conducted pursuant to PJM-MISO JOA, section 9.3.7.2(c) of in which the TMEP was identified, the Transmission Provider shall determine, in accordance with Tariff, Attachment K-Appendix, section 5.1, the average annual Transmission Congestion Charges experienced by Market Buyers in Zones and at Merchant Transmission Facilities attributable to the targeted Reciprocal Coordinated Flowgate during the two historical calendar years prior to the study year of the Targeted Market Efficiency Project study. In making this determination, the Transmission Provider shall net any increases in Day-ahead and Real-time Prices paid by Market Buyers in a Zone or at a Merchant Transmission Facility against any decreases in Day-ahead and Real-time Prices paid by Market Buyers in such Zone or at such Merchant Transmission Facility attributable to the targeted Reciprocal Coordinated Flowgate. Where a single TMEP is constructed to reduce Transmission Congestion Charges attributable to more than one targeted Reciprocal Coordinated Flowgate, the Transmission Provider shall net any increases in Day-ahead and Real-time Prices paid by Market Buyers in a Zone or at a Merchant Transmission Facility against any decreases in Day-ahead and Real-time Prices paid by Market Buyers in such Zone or at such Merchant Transmission Facility attributable to all targeted Reciprocal Coordinated Flowgates. Cost responsibility shall be assigned based on each Zone's and Merchant Transmission Facility's pro rata share of the sum of the net Transmission Congestion Charges paid by Market Buyers only of the Zones and Merchant Transmission Facilities in which Market Buyers experienced net Transmission Congestion Charges.

(xviii) Required Transmission Enhancements Designed to Address Stability Issues. For purposes of the assignment of cost responsibility for Reliability Projects designed to address stability issues under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of this Schedule 12, the Transmission Provider shall, using the same inputs and assumptions from the simulation that originally drove the need for the stability upgrade, perform a stability simulation that includes the stability upgrade under the worst fault condition. The worst fault condition shall be the fault condition in the simulation that produces the maximum rotor angle swing with the stability upgrade included. For each load bus on the system, the difference between the highest and lowest voltage angle that occurs during the simulation of the worst fault condition will be recorded. Load buses having a voltage angle deviation less than 25 percent of the load bus with the largest voltage angle deviation will not be included in the cost allocation calculation. For the remaining load buses, the voltage angle deviation will be multiplied by the megawatt load at the bus obtained from the stability simulation model, or, in the case of a Merchant Transmission Facility, the Firm Transmission Withdrawal Rights at the bus. The products of the voltage angle deviation and megawatt load at each bus will be summed for each Responsible Zone. The

Stability Deviation cost allocation for a Responsible Zone or Merchant Transmission Facility will be determined by dividing the sum of the load-weighted angle deviations for the Responsible Zone or Merchant Transmission Facility by the sum of the load-weighted angle deviations for each Responsible Zone and Merchant Transmission Facility. Transmission Provider shall round cost responsibility assignments to the nearest one-hundredth of one percent.

(xix) Regional Facilities and Necessary Lower Voltage Facilities Included in the Long-Term Regional Transmission Plan. The Transmission Provider shall assign cost responsibility for Required Transmission Enhancements included in the Long-Term Regional Transmission Plan in accordance with section (b) of this Schedule 12, as applicable, except as set forth in this section (b)(xix):

(A) Cost responsibility for all Regional Facilities and Necessary Lower Voltage Facilities included in the Long-Term Regional Transmission Plan solely to address Core LT Needs shall be allocated among Responsible Customers as defined in this Schedule 12 as follows:

(1) Fifty percent (50%) shall be assigned annually in accordance with section (b)(i)(A)(1)(a) or (b)(i)(A)(1)(b) of this Schedule 12, as applicable, and

(2) Fifty percent (50%) shall be assigned in accordance with section (b)(iii) of this Schedule 12.

(B) Cost responsibility for all Regional Facilities and Necessary Lower Voltage Facilities included in the Long-Term Regional Transmission Plan solely to address Additional LT Needs shall be allocated among Responsible Customers as defined in this Schedule 12 as follows:

(1) Fifteen percent (15%) shall be assigned annually in accordance with section (b)(i)(A)(1)(a) or (b)(i)(A)(1)(b) of this Schedule 12, as applicable, and

(2) Eighty-five percent (85%) shall be assigned in accordance with section (b)(iii) of this Schedule 12.

(C) (1) Cost responsibility for a Required Transmission Enhancement that is a Regional Facility or a Necessary Lower Voltage Facility included in the Long-Term Regional Transmission Plan to address both Core LT Needs and Additional LT Needs shall be assigned to Responsible Customers as defined in this Schedule 12 as follows:

(a) The costs of facilities that would be required to address only the Core LT Needs addressed by such Required Transmission Enhancement shall be assigned in accordance with section (xix)(A). The cost of facilities that would be required to address only the Core LT Needs addressed by such Required Transmission Enhancement shall be determined by the cost of such facilities included in the Core Plan; and

(b) The cost of the facilities required to address the Additional LT Needs addressed by such Required Transmission Enhancement shall be assigned in accordance with section (xix)(B). The Transmission Provider shall determine the cost of the facilities required

to address the Additional LT Needs addressed by such Required Transmission Enhancement at the time the PJM Board approves such Required Transmission Enhancement for inclusion in the Long-Term Regional Transmission Plan pursuant to Operating Agreement, Schedule 6-C, section 1.17(a) by subtracting the cost determined pursuant to section (b)(xix)(C)(1)(a) from the total cost of such Required Transmission Enhancement. Such determination shall be used to determine the percentage of the annual revenue requirement assigned pursuant to section (b)(xix)(A) and (b)(xix)(B), respectively.

(2) Cost responsibility for a Required Transmission Enhancement that is a Lower Voltage Facility included in the Long-Term Regional Transmission Plan to address either Core LT Needs or Additional LT Needs or both shall be assigned to Responsible Customers as defined in this Schedule 12 in accordance with section (b)(iii) of this Schedule 12.

(D) If a Voluntary Funding Entity proposes a Voluntary Funding Agreement pursuant to Operating Agreement, Schedule 6-C, section 1.14 (Voluntary Funding for Long-Term Transmission Project(s) Addressing Additional LT Needs) to assign the cost of a Required Transmission Enhancement included in the All-in-One Plan to Responsible Customers, the Transmission Provider shall submit such assignment of costs to the Transmission Owners Agreement Administrative Committee for consideration and filing pursuant to Consolidated Transmission Owners Agreement, section 7.3 and Tariff, Part I, section 9.1(a). Nothing in this section (b)(xix)(D) shall prevent the Transmission Provider or such Voluntary Funding Entity from filing a proposed assignment of costs to Responsible Customers for such Required Transmission Enhancement pursuant to Section 206 of the Federal Power Act. If approved by the Commission, the assignment of costs of such Required Transmission Enhancement to Responsible Customers under such Voluntary Funding Agreement shall supersede any such assignment pursuant to section (b)(xix)(B) or (b)(xix)(C)(1)(b) as applicable.

(E) If within six months following the approval of a Long-Term Regional Transmission Plan, the PJM Area Relevant State Entities Committee members agree pursuant to a State Agreement Process they have adopted to a State Cost Assignment Agreement to assign the costs of a Required Transmission Enhancement included in the Long-Term Regional Transmission Plan to Responsible Customers and provide such State Cost Assignment Agreement to the Transmission Provider, the Transmission Provider shall submit such proposed assignment of costs to the Transmission Owners Agreement Administrative Committee for consideration and filing pursuant to Consolidated Transmission Owners Agreement, section 7.3 and Tariff, Part I, section 9.1(a). Nothing in this section (b)(xix)(E) shall prevent the Transmission Provider or the PJM Area Relevant State Entities Committee from filing a proposed assignment of costs to Responsible Customers for such Required Transmission Enhancement pursuant to Section 206 of the Federal Power Act. If such assignment of costs is approved by the Commission, the assignment of costs of such Required Transmission Enhancement to Responsible Customers shall supersede any such assignment pursuant to section (b)(xix)(A), (b)(xix)(B) or (b)(xix)(C)(1) as applicable.

(F) If an agreement under either section (b)(xix)(D) or (b)(xix)(E) is approved by the Commission requiring the assignment of cost responsibility for a Required Transmission Enhancement included in the Long-Term Regional Transmission Plan to Responsible Customers within the borders of certain states that are part of a multi-state Zone and neither such agreement

nor other agreement approved or accepted by the Commission or the relevant authorities in such states identifies the Responsible Customers in each state, the Transmission Provider shall identify the Responsible Customers according to the following formula:

CS=(ASPL/AZPL) x CRTE

Where:

CS is the total cost assigned to Responsible Customers within a state or portion thereof that is part of a multi-state Zone

ASPL is the load of Responsible Customers in a state or portion thereof that is part of a multi-state zone coincident with the annual zonal peak load determined pursuant to section (b)(i)(A)(1)(A)

AZPL is the zonal peak load determined pursuant to section (b)(i)(A)(1)(A)

CRTE is the annual revenue requirement of the Required Transmission Enhancement

The total cost of a Required Transmission Enhancement assigned to Responsible Customers within a state shall be assigned to individual Responsible Customers based on the applicable methodology utilized in such state or Zone to assign costs to Responsible Customers. Nothing in this Schedule 12 shall authorize the Transmission Provider to assign the cost of Required Transmission Enhancements to Responsible Customers based on the state in which such Responsible Customers are located, except as required as a result of an agreement under section (b)(xix)(D) or (b)(xix)(E).

(G) The Transmission Owners Agreement Administrative Committee shall consult with the PJM Area Relevant State Entities Committee with respect to any proposed amendments to this section (b)(xix) of Schedule 12 as follows:

(1) No less than 30 days prior to any Section 205 filing by the Transmission Owners Agreement Administrative Committee; and

(2) No less than 30 days after receipt of a notice addressed to the Chair of the Administrative Committee that the PJM Area Relevant State Entities Committee have agreed to request the Transmission Owners Agreement Administrative Committee to make a Section 205 filing.

Following any consultation under this section (G), the Transmission Owners Agreement Administrative Committee shall post on the PJM Website the results of such consultation with the PJM Area Relevant State Entities Committee. If the Transmission Owners Agreement Administrative Committee initiated the consultation, such posting shall be made prior to filing their proposed amendment to this section (b)(xix). If the PJM Area Relevant State Entities Committee initiated the consultation and the Transmission Owners Agreement Administrative Committee declined to file an amendment to this section (b)(xix) pursuant to Consolidated

Transmission Owners Agreement, section 7.3 and Tariff, Part I, section 9.1(a), the Transmission Owners Agreement Administrative Committee shall post on the PJM Website the results of such consultation with PJM Area Relevant State Entities Committee, including an explanation for why it has declined to propose any amendments. Nothing in this section (b)(xix)(G) shall prevent the Transmission Provider or the PJM Area Relevant State Entities Committee from filing a proposed amendment to this section (b)(xix) pursuant to Section 206 of the Federal Power Act.

(c) Determination of Transmission Enhancement Charges. In the event that any Transmission Owner recovers the cost of a Required Transmission Enhancement through a Transmission Enhancement Charge, such charge shall be determined as follows:

(1) Transmission Provider shall identify in writing and post on the PJM Internet site the Required Transmission Enhancement(s) to which each Transmission Enhancement Charge corresponds. The Transmission Enhancement Charge with respect to a Required Transmission Enhancement shall recover the applicable Transmission Owner's annual transmission revenue requirement associated with the Required Transmission Enhancement.

(2) Each Transmission Enhancement Charge shall be a monthly charge based on all costs and applicable incentives associated with a particular Required Transmission Enhancement for which the Transmission Owner is responsible.

(3) A Transmission Owner's annual transmission revenue requirement associated with a Required Transmission Enhancement shall be determined pursuant to either (i) a unilateral filing by the Transmission Owner under Section 205 of the Federal Power Act and the FERC's rules and regulations thereunder; or (ii) a formula rate in effect applicable to the Transmission Owner's rates for Network Integration Transmission Service, including the costs associated with Required Transmission Enhancements.

(4) Each Transmission Enhancement Charge applicable to Network Customers and Non-Zone Network Customers shall be recalculated annually to reflect the annual revisions to the billing determinants used by the Transmission Provider to calculate charges to Network Customers for Network Integration Transmission Service under Tariff, Part III, section 34.1. The Transmission Provider shall post on its Internet site by October 31 of each calendar year each recalculated Transmission Enhancement Charge that shall be effective during the subsequent calendar year.

(5) Each Transmission Enhancement Charge applicable to customers using Point-To-Point Transmission Service shall be calculated monthly to reflect the billing determinants used by the Transmission Provider to determine charges for customers of Point-To-Point Transmission Service in accordance with Tariff, Part II, section 25.

(6) Each Transmission Enhancement Charge payable by an owner of a Merchant Transmission Facility pursuant to section (b) of this Schedule 12 shall be calculated as a fixed monthly charge.

(7) If a Transmission Owner chooses to recover the cost of Required Transmission Enhancements through the operation of a formula rate as described in section (a) of this Schedule 12, the Transmission Owner must make an informational filing with the Commission one year from the date the selecting Transmission Owner's formula rates go into effect, and each year thereafter, providing a detailed list of the costs the Transmission Owner has incurred, and the revenues the Transmission Owner has received to provide service.

(d) Recovery of Transmission Enhancement Charges.

(1) Responsible Customers shall pay Transmission Provider all applicable Transmission Enhancement Charges as required by this Schedule 12 in addition to all other charges for transmission service for which such Responsible Customers are responsible under the Tariff.

(2) Transmission Provider shall collect all applicable Transmission Enhancement Charges from each Responsible Customer on a monthly basis. Transmission Provider shall remit or credit all revenues received from Responsible Customers under this Schedule 12 to the Transmission Owner(s) that established such charge or to the appropriate authority in a region other than PJM in the case of Transmission Enhancement Charges established in such region in connection with a Required Transmission Enhancement constructed pursuant to an Appendix B Agreement, to be distributed in accordance with the applicable tariff or agreement governing the distribution of such charges in such region.

(e) Crediting of Revenue from Transmission Enhancement Charges. In recognition that a Transmission Owner's charges for Network Integration Transmission Service set forth in Tariff, Attachment H are established based upon the Transmission Owner's total cost of providing FERC-jurisdictional transmission service, including the costs associated with Required Transmission Enhancements, revenue from a Transmission Owner's Transmission Enhancement Charges for a billing month shall be credited pursuant to this Schedule 12 to the Network Customers in the Transmission Owner's Zone (including, where applicable, the Transmission Owner) and Transmission Customers purchasing Firm Point-to-Point Transmission Service for delivery in the Transmission Owner's Zone in proportion to their Demand Charges (including any imputed Demand Charges for bundled service to Native Load Customers) for Network Integration Transmission Service and Reserved Capacity for Firm Point-to-Point Transmission Service; provided that such credits shall be reduced by the amount of any applicable incentives included in such Transmission Enhancement Charges.

Attachment B

Revisions to the PJM Open Access Transmission Tariff

(Clean Format)

Included within this Attachment B:

- Definitions A-B
- Definitions C-D
- Definitions L-M-N
- Definitions O-P-Q
- Definitions R-S
- Definitions T-U-V
- Schedule 12

Definitions – A - B

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

"Abnormal Condition" shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Additional LT Needs:

"Additional LT Needs" shall have the meaning set forth in the Operating Agreement.

Affected System:

"Affected System" shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the

Transmission System.

Affected System Operator:

"Affected System Operator" shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

"Agreements" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

All-in-One Plan:

"All-in-One Plan" shall have the meaning set forth in the Operating Agreement.

Ambient-Adjusted Rating:

"Ambient-Adjusted Rating" (AAR) shall mean a Transmission Facility Rating that:

(a) Applies to a time period of not greater than one hour.
(b) Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.
(c) Reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently.
(d) Is evaluated at least each hour, if not more frequently.

Ancillary Services:

"Ancillary Services" shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

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

Annual Energy Efficiency Resource:

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

Annual Resource:

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

Annual Resource Price Adder:

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, 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.

Annual Revenue Rate:

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

"Annual Transmission Costs" shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

"Applicable Laws and Regulations" shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

"Applicable Technical Requirements and Standards" shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, "Applicable Technical Requirements and Standards" shall refer to the "PJM Small Generator Interconnection Applicable Technical Requirements and Standards." All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider's internet website.

Applicant:

"Applicant" shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

"Application" shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

"Attachment Facilities" shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

"Attachment H" shall refer collectively to the Attachments to the PJM Tariff with the prefix "H" that set forth, among other things, the Annual Transmission Rates for Network Integration

Transmission Service in the PJM Zones.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

"Authorized Government Agency" means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

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

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

"Balancing Ratio" shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

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

Base Capacity Demand Resource Constraint:

"Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for 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 Installed Reserve Margin 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 Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint 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 forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

"Base Capacity Demand Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

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

Base Capacity Resource:

"Base Capacity Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

"Base Capacity Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (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 weekly load distribution (based on the Installed Reserve Margin study and 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 Installed Reserve Margin 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. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint 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 [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

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.

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.

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.

Batch Load Economic Load Response Participant Resource:

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

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generation 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 has 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 Generation Capacity Resource; or (ii) in an 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.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

"Business Day" shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

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

Buyer-Side Market Power:

"Buyer-Side Market Power" shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – C - D

Canadian Guaranty:

"Canadian Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

"Capacity Interconnection Rights" shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

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

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.

Capacity Performance Resource:

"Capacity Performance Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

"Capacity Performance Transition Incremental Auction" shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

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

Capacity Resource with State Subsidy:

"Capacity Resource with State Subsidy" shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

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 Tariff, Attachment DD, section 5.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

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.

Capacity Transmission Injection Rights:

"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource or Open-Loop Hybrid Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Charge Mode. Charge Economic Minimum

Megawatts shall be the Economic Maximum for an Energy Storage Resource or Open-Loop Hybrid Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Charge Mode.

Cleared Capacity Resource with State Subsidy:

"Cleared Capacity Resource with State Subsidy" shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Closed-Loop Hybrid Resource:

"Closed-Loop Hybrid Resource" shall mean a Hybrid Resource that does not operate by charging its storage component from the grid.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval

from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

"Collateral" shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. "Collateral" shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

"Collateral Call" shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Co-Located Resource:

"Co-Located Resource" shall mean a component of a Mixed Technology Facility that operates in the capacity, energy, and/or ancillary services market(s) as a separate resource from the other components of such facility.

Commencement Date:

"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The "Committed Offer" shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected

to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

"Completed Application" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Component DER:

"Component DER" shall mean any resource, within the PJM Region, that is located on a distribution system, any subsystem thereof, or behind a customer meter, and is used in a DER Aggregation Resource by a DER Aggregator to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model. A Component DER may not exceed 5 MW.

Composite Energy Offer:

"Composite Energy Offer" for generation resources shall mean the sum (in $/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in $/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

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.

Conditioned State Support:

"Conditioned State Support" shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where "conditioned on clearing in any RPM Auction" refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

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

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

"Construction Service Agreement" shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

"Contingent Facilities" shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

"Continuous Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants or Open-Loop Hybrid Resource operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

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 automatic generation control scheme is applied in order to:

(1) 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);

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

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

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

Control Zone:

"Control Zone" shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

"Controllable A.C. Merchant Transmission Facilities" shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Core LT Needs:

"Core LT Needs" shall have the meaning set forth in the Operating Agreement.

Core Plan:

"Core Plan" shall have the meaning set forth in the Operating Agreement.

Corporate Guaranty:

"Corporate Guaranty" shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

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 Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, "Costs" shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

Credit Affiliate:

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

"Credit Available for Export Transactions" shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for

Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and

the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

Critical Natural Gas Infrastructure:

"Critical Natural Gas Infrastructure" shall mean locations with electrical loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility as defined by NERC/FERC standard(s); and until such NERC/FERC standard(s) is developed, is defined as electric loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility, which if curtailed, will impact the delivery of natural gas to bulk-power system natural gas-fired generation.

Cross-Border:

When used to describe Network Integration Transmission Service, Network External Designated Transmission Service or Point-to-Point Transmission Service, "Cross-Border" shall mean transmission service where the capacity and/or energy is delivered from a resource that is not part of the PJM Transmission System and/or to load that is not part of the PJM Transmission System.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

"Customer Facility" shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

"Customer-Funded Upgrade" shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

"Customer Interconnection Facilities" shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

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

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 Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-Ahead Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

"Deactivation" shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

"Deactivation Avoidable Cost Credit" shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

"Deactivation Avoidable Cost Rate" shall mean the formula rate established pursuant to Tariff, Part V, section 115.

Deactivation Date:

"Deactivation Date" shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

"Decrement Bid" shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, "Default" shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

"Delivering Party" shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

"Delivery Year" shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

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

Demand Resource Factor or DR Factor:

"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

DER Aggregation Resource:

"DER Aggregation Resource" shall be comprised of one or more Component DER. A DER Aggregation Resource is used by a DER Aggregator to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model. A DER Aggregation Resource is capable of satisfying a minimum energy and/or ancillary services market offer of 100 kW. The market participation eligibility of a DER Aggregation Resource shall be determined in accordance with the physical and operational characteristics of the underlying Component DER that comprise the DER Aggregation Resource.

DER Aggregator:

"DER Aggregator" shall mean an entity that is a Market Participant that: (i) uses one or more DER Aggregation Resources to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model; and (ii) has a fully-executed DER Aggregator Participation Service Agreement.

DER Aggregator Participation Model:

"DER Aggregator Participation Model" shall mean the participation model described in Tariff, Attachment K-Appendix, section 1.4B.

DER Capacity Aggregation Resource:

"DER Capacity Aggregation Resource" shall mean one or more DER Aggregation Resource that participates in the Reliability Pricing Model, capable of satisfying a minimum capacity market offer of 100 kW, or is otherwise treated as capacity in PJM's markets, such as through a Fixed Resource Requirement Capacity Plan, for the 2028/2029 Delivery Year and all subsequent Delivery Years.

Designated Agent:

"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the

Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource or Open-Loop Hybrid Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource or Open-Loop Hybrid Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource or Open-Loop Hybrid Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is only injecting megawatts onto the grid).

Discharge Ramp Rate:

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Discharge Mode.

Dispatch Rate:

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

Dispatched Charging Energy:

"Dispatched Charging Energy" shall mean Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants and Open-Loop Hybrid Resource shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

"Dynamic Schedule" shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

"Dynamic Transfer" shall have the same meaning provided in the Operating Agreement.

Definitions – L – M – N

Legacy Policy:

"Legacy Policy" shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

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

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 Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years 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; 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; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly 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 a Monte Carlo model of hourly capacity levels that is consistent with the capacity model 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) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three 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].

Limited Resource Constraint:

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:
"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

"Load Interest" shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource or Open-Loop Hybrid Resource for later resale to end-use load.

Load Serving Entity (LSE):

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

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

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 Reliability Assurance Agreement, Schedule 10.1.

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.

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.

Locational Reliability Charge:

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

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.

Locational UCAP Seller:

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

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Long-Term Regional Transmission Plan:

"Long-Term Regional Transmission Plan" shall have the meaning set forth in the Operating Agreement.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

"Marginal Value" shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

"Market Monitor**"** means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

"Market Monitoring Unit Advisory Committee" or "MMU Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

"Market Participant" shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

"Market Participant Energy Injection" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

"Market Participant Energy Withdrawal" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

"Market Revenue Neutrality Offset" shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

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 Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

"Market Violation" shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

"Material Modification" shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

"Maximum Daily Starts" shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:

"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any

physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, 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 Tariff, Attachment DD, section 5.10(a) 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 Sub-Annual 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 LDA CETL] minus [the Sub-Annual 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.

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, 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 Tariff, Attachment DD, section 5.10(a) 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 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 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.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

"Mixed Technology Facility" shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

"MOPR Floor Offer Price" shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

"Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

"Native Load Customers" shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner's system to meet the reliable electric needs of such customers.

Near-Term Transmission Service:

"Near-Term Transmission Service" shall mean Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date. "Near-Term Transmission Service" includes any Point-To-Point Transmission Service and Network Integration Transmission Service where the start and end date of the designation or request is within the next 10 days.

NERC:

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

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

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.

Net Obligation:

"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III.

Network Load:

"Network Load" shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer's Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving

Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

"Network Operating Agreement" shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

"Network Operating Committee" shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

"Network Resource" shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

"Network Service User" shall mean an entity using Network Transmission Service.

Network Transmission Service:

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

Network Upgrades:

"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direcct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

"Neutral Party" shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

"New Entry Capacity Resource with State Subsidy" shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

"New Services Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

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.

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.

Non-Curtailment Charge:

"Non-Curtailment Charge" shall mean the charge applicable to Demand Resources and Price Responsive Demand as defined in Tariff, Attachment DD, section 10B(b).

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm

Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-PAI Event:

"Non-PAI Event" shall mean, effective for the 2028/2029 Delivery Year and subsequent Delivery Years, any intervals when a Demand Resource is dispatched or when Price Responsive Demand is required to respond and a Performance Assessment Interval is not in effect for such intervals for the same registration.

Non-Performance Charge:

"Non-Performance Charge" shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

"Nonincumbent Developer" shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

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, or electric distribution companies to serve load.

Non-Synchronized Reserve:

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

"Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

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

Normal Minimum Generation:

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

Definitions – O – P - Q

Obligation:

"Obligation" shall mean all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Tariff, Part II and Tariff, Part III), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for capacity purchases within the PJM capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Offer Data:

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

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.

Office of the Interconnection Control Center:

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

On-Site Generators:

"On-Site Generators" shall mean generation facilities or portions of a generation facility (including Behind The Meter Generation) that (i) are not Generation Capacity Resources, (ii) are not injecting into the grid for the portion of a generation facility that participates as a Demand Resource or as an Economic Load Response Participant unless permitted as an Economic Load Response Regulation Only Participant, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-Time Information System" or "OASIS" shall mean the electronic communication and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Open-Loop Hybrid Resource:

"Open-Loop Hybrid Resource" shall mean a Hybrid Resource with a storage component that operates by charging its storage component from the grid.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve Demand Curve:

"Operating Reserve Demand Curve" shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that

can be used to meet a given reserve requirement.

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy from the external Generation Capacity Resource to loads in the PJM Region in a manner comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

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

OPSI Advisory Committee:

"OPSI Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

"Option to Build" shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

"Optional Interconnection Study" shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

"Optional Interconnection Study Agreement" shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

"Part I" shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

"Part II" shall mean Tariff, Part II, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

"Part III" shall mean Tariff, Part III, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

"Part IV" shall mean Tariff, Part IV, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

"Part V" shall mean Tariff, Part V, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

"Part VI" shall mean Tariff, Part VI, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

"Participant" shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer**.**

Parties:

"Parties" shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-ahead Energy Market 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 day-ahead 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), plus 10% of such costs only for the 2022/2023 Delivery Year, for at least two hours during each four-hour block, where such blocks shall be assumed to be committed 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 committed for such block; and to the extent not committed in any such block in the Day-ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate, plus 10% of such costs only for the 2022/2023 Delivery Year, under the same conditions as described above for the Day-ahead Energy Market.

Peak Market Activity:

"Peak Market Activity" shall mean a measure of exposure for which credit is required, calculated in accordance with Tariff, Attachment Q, section VII.A.

Peak Market Activity Shortfall:

"Peak Market Activity Shortfall" shall mean, for any given week, the amount by which a Participant's current Peak Market Activity exceeds such Participant's Peak Market Activity credit requirement from the prior week.

Peak Market Activity Surplus:

"Peak Market Activity Surplus" shall mean, for any given week, the amount by which a Participant's Peak Market Activity credit requirement from the prior week exceeds such Participant's current Peak Market Activity.

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.

Percentage Internal Resources Required:

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

Performance Assessment Interval:

"Performance Assessment Interval" shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September.

Permissible Technological Advancement:

"Permissible Technological Advancement" shall mean a proposed technological change such as an advancement to turbines, inverters, plant supervisory controls or other similar advancements to the technology proposed in the Interconnection Request that is submitted to the Transmission Provider no later than the return of an executed Facilities Study Agreement (or, if a Facilities Study is not required, prior to the return of an executed Interconnection Service Agreement). Provided such change may not: (i) increase the capability of the Generating Facility as specified in the original Interconnection Request; (ii) represent a different fuel type from the original Interconnection Request; or (iii) cause any material adverse impact(s) on the Transmission System with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response. If the proposed technological advancement is a Permissible Technological Advancement, no additional study will be necessary and the proposed technological advancement will not be considered a Material Modification.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

"PJM Administrative Service" shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Area Relevant State Entities Committee:

"PJM Area Relevant States Entities Committee" shall have the meaning set forth in the Operating Agreement.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

"PJM Control Area" shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

"PJM Entities" shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM's officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

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

PJM Interchange Energy Market:

"PJM Interchange Energy Market" shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

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

PJM Interchange Import:

"PJM Interchange Import" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the interval scheduled deliveries of

Spot Market Energy to an External Market Buyer; or (d) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Liaison:

"PJM Liaison" shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

"PJM Management" shall mean the officers, executives, supervisors and employee managers of PJM.

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 and the PJM Interchange Energy Market.

PJM Markets:

"PJM Markets" shall mean the PJM Interchange Energy Market, capacity markets, including the RPM auctions, and any other market operated by PJM, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions, Financial Transmission Rights transactions, or transactions in any other market operated under the Agreements within the PJM Region, wherein Market Participants may incur Obligations to PJM and/or PJMSettlement.

PJM Market Rules:

"PJM Market Rules" shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

"PJM Net Assets**"** shall mean the total assets per PJM's consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

"PJM Region" shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:
"PJM Regional Practices Document" shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

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

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 Tariff, Attachment DD, section 5.

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.

PJMSettlement:

"PJM Settlement" or "PJM Settlement, Inc." shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operaitng Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T.," "OATT," or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

"Plan" shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

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

Planned External Generation Capacity Resource:

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

Planned Generation Capacity Resource:

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

Planning Period:

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

Planning Period Balance:

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

Planning Period Quarter:

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

Point(s) of Delivery:

"Point(s) of Delivery" shall mean the point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

"Point of Interconnection" shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

"Point(s) of Receipt" shall mean point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission

Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

"Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

"Power Purchaser" shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

"PRD Curve" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Provider:

"PRD Provider" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Reservation Price:

"PRD Reservation" Price shall have the meaning provided in the Reliability Assurance Agreement.

PRD Substation:

"PRD Substation" shall have the meaning provided in the Reliability Assurance Agreement.

Pre-Confirmed Application:

"Pre-Confirmed Application" shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

"Pre-Emergency Load Response Program" shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Pre-Expansion PJM Zones:

"Pre-Expansion PJM Zones" shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC ("MAIT") (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

"Price Responsive Demand" shall have the meaning provided in the Reliability Assurance Agreement.

Primary Reserve:

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Alert

"Primary Reserve Alert" shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

"Primary Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Principal:

"Principal" shall mean (i) all natural persons who Control Corporate Level Strategy for the Participant, which shall include a chief executive officer, managing member (or equivalent positions regardless of title) and members of a board of directors or board of managers; (ii) the chief legal officer or general counsel (or equivalent position regardless of title); (iii) the natural person who Controls the financial affairs and investments of the Participant, which shall include a chief financial officer (or equivalent position regardless of title); (iv) the natural person who Controls the Participant's management of commodity and derivatives market risks, which shall include a chief risk officer (or equivalent position regardless of title); (v) the natural person who Controls the Participant's transactions in the applicable PJM Markets (regardless of title); and (vi) all Beneficial Owners.

"Control," as that term is used in this definition, refers to possession of the power to direct the management or policies of an entity.

"Corporate Level Strategy," as that term is used in this definition, refers to the highest-level strategy of an entity, focused on the entity's overall direction rather than the day-to-day operations of the entity.

"Beneficial Owner," as that term is used in this definition, means a natural person who, directly or indirectly, alone or together with such person's Family Members, owns, controls, or holds with power to vote 10 percent or more of the outstanding securities of the Participant.

"Family Member," as that term is used in this definition of "Beneficial Owner," means a spouse, domestic partner, parent, child, or sibling.

For purposes of trusts with, directly or indirectly, 10 percent or more of the outstanding securities of the Participant as described above, the following are Beneficial Owners: (a) a natural person trustee; (b) a natural person with the authority to dispose of the trust assets; (c) a natural person grantor or settlor who has the right to revoke the trust or otherwise withdraw the assets of the trust; and (d) a natural person beneficiary who is the sole permissible recipient of income and principal from the trust or has the right to demand a distribution of or withdraw substantially all of the assets from the trust.

If, due to the Participant's business enterprise, structure or otherwise, a function described in clauses (i) through (v) above is performed by a natural person or entity separate from the Participant (such as a risk management department in an affiliate, or a director or manager at an entity that controls or invests in the Participant), then for that Participant the term Principal shall mean that natural person, or the senior officer or manager of that entity, that performs such function.

Prior CIL Exception External Resource:

"Prior CIL Exception External Resource" shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

"Project Financing" shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

"Project Finance Entity" shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

Projected EAS Dispatch:

"Projected EAS Dispatch" shall mean, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource's offer and operating parameters. For combustion turbine units only, the cost-based energy offer will include a 10 percent adder only for the 2022/2023 Delivery Year.

Projected PJM Market Revenues:

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

Proportional Multi-Driver Project:

"Proportional Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Provisional Interconnection Service:

"Provisional Interconnection Service" shall mean interconnection service provided by Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interconnection Service Agreement and, if applicable, the Tariff.

Pseudo-Tie:

"Pseudo-Tie" shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

"Public Policy Objectives" shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

"Public Policy Requirements" shall have the same meaning provided in the Operating Agreement.

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.

Queue Position:

"Queue Position" shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

Definitions – R - S

Ramping Capability:

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

Real-time Congestion Price:

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Offer:

"Real-time Offer" shall mean a new offer or an update to a Market Seller's existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Settlement Interval:

"Real-time Settlement Interval" shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

"Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/ MWh.

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and

decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM 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, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

"Regional Transmission Enhancements" shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that 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 constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

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.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

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

Schedule of Work:

"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Seasonal Facility Rating:

"Seasonal Facility Rating" shall mean a Transmission Facility Rating that:

(a) Applies to a specified season, where seasons are defined by the Office of the Interconnection to include not fewer than four seasons in each year, and to reasonably reflect portions of the year where expected high temperatures are relatively consistent.

(b) Reflects an up-to-date forecast of ambient air temperature across the relevant season over which the rating applies.

(c) Is evaluated annually, if not more frequently, for each season in the future for which Transmission Service can be requested

Secondary Reserve:

"Secondary Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes (less the capability of such resources to provide Primary Reserve), from the request of the Office of the Interconnection, regardless of whether the equipment providing the reserve is electrically synchronized to the Transmission System or not.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

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

Security:

"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

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.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "vertically integrated utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "public power entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

"Self-Supply Seller" shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where "vertically integrated utility" means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and "public power entity" means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

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

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

"Short-term Project" shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, 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.

Short-Term Resource Procurement Target Applicable Share:

"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (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.

Site:

"Site" shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

"Small Commercial Customer," as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start Fuel:

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours)

Start-Up Costs:

"Start-Up Costs" shall consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units): Start-Up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.

For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-Up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

"State Commission**"** shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

"State Subsidy" shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction,

development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State Agreement Process:

"State Agreement Process" shall have the meaning as set forth in Order No. 1920, *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 89 FR 49280 (June 11, 2024), 187 FERC ¶ 61,068, P 45 (2024).

State Cost Assignment Agreement:

"State Cost Assignment Agreement" shall mean an agreement among entities legally authorized to enter into such an agreement to assign costs of a Required Transmission Enhancement and submitted to the Transmission Owners Agreement Administrative Committee pursuant to Tariff, Schedule 12, section (b)(xix)(E).

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in the storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or Hybrid Resource using minimum and maximum discharge (and,

as applicable, charge) limits, changes in operating mode (as applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-Annual Resource Constraint:

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

"Sub-Annual 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 for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource 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 Sub-Annual 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].

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within

the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment

priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

Definitions – T – U - V

Tangible Net Worth:

"Tangible Net Worth" shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

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

Third-Party Sale:

"Third-Party Sale" shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

"Tie Line" shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost

Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

"Total Net Obligation" shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

"Total Net Sell Position" shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Trade Reference:

"Trade Reference" shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement,

Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

"Transmission Constraint Penalty Factor" shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

"Transmission Customer" shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

"Transmission Facilities" shall have the meaning set forth in the Operating Agreement.

Transmission Facility Rating:

"Transmission Facility Rating" shall mean the maximum transfer capability, or the maximum or minimum voltage, current, frequency, or real or reactive power flow, through a Transmission Facility that does not violate the applicable rating of relevant transmission equipment. Transmission Facility Ratings are computed in accordance with a written Transmission Facility Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers. Transmission Facility Ratings also encompass AARs, AAR Exceptions, and Temporary Conditional Transmission Facility Ratings.

Transmission Forced Outage:

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Injection Rights:

"Transmission Injection Rights" shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

"Transmission Interconnection Customer" shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

"Transmission Interconnection Facilities Study" shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

"Transmission Interconnection Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

"Transmission Interconnection Request" shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

"Transmission Owner Attachment Facilities" shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner's side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

"Transmission Owner Interconnection Facilities" shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner's side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

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

Unsecured Credit:

"Unsecured Credit" shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

"Unsecured Credit Allowance" shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: "Working Credit Limit."

Updated VRR Curve:

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

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 and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

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 and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

"Upgrade Construction Service Agreement" shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

"Upgrade Customer" shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

"Upgrade Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

"Upgrade-Related Rights" shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

"Upgrade Request" shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

"Up-to Congestion Counterflow Transaction" shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

"Up-to Congestion Historical Month" shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an "Up-to Congestion Prevailing Flow Transaction" if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

"Up-to Congestion Reference Price" for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30^{th} percentile
For Up-to Congestion Counterflow Transactions when bid: 20^{th} percentile
For Up-to Congestion Counterflow Transactions when cleared: 5^{th} percentile

Up-to Congestion Transaction:

"Up-to Congestion Transaction" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

"Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

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 Tariff, Attachment DD, section 5.

Virtual Credit Exposure:
"Virtual Credit Exposure" shall mean the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

"Virtual Transaction Screening" shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

"Virtual Transactions Net Activity" shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

"Voltage Reduction Action" shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

"Voltage Reduction Alert" shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

"Voltage Reduction Warning" shall mean a notification from PJM to warn Members that PJM's available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

Voluntary Funding Agreement:

"Voluntary Funding Agreement" shall mean an agreement among entities legally authorized to enter into such an agreement to assign the costs of a Required Transmission Enhancement and

submitted to the Transmission Owners Agreement Administrative Committee pursuant to Tariff, Schedule 12, section (b)(xix)(D).

Voluntary Funding Entity:

“Voluntary Funding Entity" shall have the meaning set forth in the Operating Agreement.

SCHEDULE 12
Transmission Enhancement Charges

(a) Establishment of Transmission Enhancement Charges.

(i) Establishment of Transmission Enhancement Charges by Transmission Owners and Entities That Will Become Transmission Owners. One or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements by (1) the Regional Transmission Expansion Plan periodically developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") (collectively, for purposes of this Schedule 12 only, "Regional Transmission Expansion Plan"). Operating Agreement, Schedule 6, section 1.7 recognizes that Transmission Owners, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Required Transmission Enhancements and obligates PJMSettlement to collect on behalf of Transmission Owner(s) any charges established by Transmission Owners to recover the costs of Required Transmission Enhancements. If a Transmission Owner is designated by the Regional Transmission Expansion Plan to construct and own and/or finance a Required Transmission Enhancement, such Transmission Owner may choose any of the following cost recovery mechanisms, subject to the crediting procedures set forth in section (e) below:

(1) Decline to seek to recover the costs of Required Transmission Enhancements from customers until such time as it makes a filing pursuant to Section 205 of the Federal Power Act to revise its Network Integration Transmission Service rates;

(2) Make a filing pursuant Section 205 of the Federal Power Act and the FERC's rules and regulations to establish the revenue requirement with respect to a Required Transmission Enhancement, without filing to revise its rates for Network Integration Transmission Service generally; or

(3) Establish the revenue requirement with respect to a Required Transmission Enhancement through the operation of a formula rate in effect applicable to its rates for Network Integration Transmission Service.

A charge established to recover the revenue requirement with respect to a Required Transmission Enhancement is hereafter referred to as a "Transmission Enhancement Charge." Transmission Enhancement Charges of one or more Transmission Owners for Required Transmission Enhancements shall be established in accordance with this Schedule 12.

(ii) Establishment of Transmission Enhancement Charges With Respect to Required Transmission Enhancements Constructed by Entities in Another Region. The revenue requirement with respect to a Required Transmission Enhancement constructed pursuant to an Appendix B Agreement in another region by an entity designated by such other region shall be governed by the tariffs or agreements in effect in such region. Transmission Enhancement Charges to recover the costs of such Required Transmission Enhancement for which PJM is

responsible shall be determined in accordance with this Schedule 12. Other than with respect to a Required Transmission Enhancement constructed pursuant to an Appendix B Agreement, no PJM Network or Transmission Customer will bear cost responsibility for any required transmission upgrades in another region as a consequence of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan.

(iii) Transmission Facilities Not Eligible for Cost Responsibility Assignment. Any alternating current ("A.C.") facilities or direct current ("D.C.") facilities that are Attachment Facilities, Local Upgrades, Merchant Network Upgrades, Merchant Transmission Facilities, Network Upgrades, Supplemental Projects, or any other Transmission Facilities that operate or are planned to be operated in a manner that requires customers to subscribe to transmission service over such facilities or to a portion of the electric capability of such facilities shall not be eligible for cost responsibility assignment pursuant to this Schedule 12.

(iv) Entities Not Yet Eligible to Become Transmission Owners. For purposes of this Schedule 12 only, the term, "Transmission Owner," shall include any entity that undertakes to construct and own and/or finance a Required Transmission Enhancement pursuant to a designation in the Regional Transmission Expansion Plan to construct and own and/or finance such Required Transmission Enhancement, even if such entity is not yet eligible to become a party to the Consolidated Transmission Owners Agreement. Nothing in the PJM Tariff nor the Consolidated Transmission Owners Agreement shall prevent an entity that undertakes to construct and own and/or finance a Required Transmission Enhancement pursuant to a designation in the Regional Transmission Expansion Plan to construct and own and/or finance such Required Transmission Enhancement from recovering the costs of such Required Transmission Enhancement through this Schedule 12.

(v) Effective Date. The assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider prior to February 1, 2013, or (2) applicable to Required Transmission Enhancements approved by the PJM Board pursuant to Operating Agreement, section 1.6 prior to February 1, 2013 are set forth in Tariff, Schedule 12-Appendix. Except as specifically set forth herein, nothing in this Schedule 12 shall change the assignment of cost responsibility or classification of Required Transmission Enhancements included in Tariff, Schedule 12-Appendix. The assignment of cost responsibility or classification of all other Required Transmission Enhancements shall be set forth in Tariff, Schedule 12-Appendix A.

(b) Designation of Customers Subject to Transmission Enhancement Charges.

(i) Regional Facilities and Necessary Lower Voltage Facilities. Transmission Provider shall assign cost responsibility on a region-wide basis for Required Transmission Enhancements included in the Regional Transmission Expansion Plan that (1) (a) are A.C. facilities that operate at or above 500 kV; (b) constitute a single Required Transmission Enhancement comprising two A.C. circuits operating at or above 345 kV and below 500 kV, where both circuits originate from a single substation or switching station at one end and terminate at a single substation or switching station at the other end, regardless of whether or not

the two circuits are routed in the same right-of-way ("Double-circuit 345 kV Required Transmission Enhancement"); (c) are A.C. or D.C. shunt reactive resources (such as capacitors, static var compensators, static synchronous condenser (STATCON), synchronous condensers, inductors, other shunt devices, or their equivalent) connected to a Transmission Facility described in clause (a) or (b) of this subsection, or (d) are D.C. facilities meeting the criteria set forth in subsection (b)(i)(D) (collectively, "Regional Facilities"), or (2) new A.C. Transmission Facilities or expansions or enhancements to existing Transmission Facilities that operate below 500 kV (or 345 kV in the case of a Regional Facility described in clause (1)(b) of this subsection) or new D.C. Transmission Facilities that do not meet the criteria of subsection (b)(i)(D) that must be constructed or strengthened to support new Regional Facilities, based on the planning criteria used by the Transmission Provider in developing the applicable Regional Transmission Expansion Plan ("Necessary Lower Voltage Facilities") as follows:

(A) Cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities shall be allocated among Responsible Customers as defined in this Schedule 12 as follows:

(1) Fifty percent (50%) shall be assigned annually on a load-ratio share basis as follows:

(a) With respect to each Zone, using, consistent with Tariff, Part III, section 34.1, the applicable zonal loads at the time of such Zone's annual peak load from the 12-month period ending October 31 preceding the calendar year for which the annual cost responsibility allocation is determined; and

(b) With respect to Merchant Transmission Facilities, (1) for the calendar year following the year in which it initiates operation, the actually awarded Firm Transmission Withdrawal Rights associated with its existing Merchant Transmission Facility; and (2) for all subsequent calendar years, the annual peak load of the Merchant Transmission Facility (not to exceed its actual Firm Transmission Withdrawal Rights) from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility allocation is determined.

(2) Fifty percent (50%) shall be assigned as follows:

(a) In the case of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to address one or more reliability violations or to address operational adequacy and performance issues (collectively, "Reliability Project"), in accordance with the distribution factor ("DFAX") analysis described in subsection (b)(iii) or the analysis applicable to Regional Facilities that address stability issues described in subsection (b)(xviii) of this Schedule 12 as applicable; and

(b) In the case of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to relieve one or more economic constraints as described in Operating Agreement, Schedule 6, section 1.5.7(b)(iii) ("Economic Project"), in accordance with the methodology described in subsection (b)(v) of this Schedule 12.

(B) (1) Except for transformers that are an integral component of a Regional Facility, transformers connected to Lower Voltage Facilities, as defined in section (b)(ii) of this Schedule 12, shall not be considered Regional Facilities or Necessary Lower Voltage Facilities; and (2) Transmission Facilities that are not Regional Facilities and deliver energy from a Regional Facility to load shall not be considered Necessary Lower Voltage Facilities.

(C) With respect Required Transmission Enhancements that qualify as Regional Facilities under subsection (b)(i)(1)(b) or subsection (b)(i)(D)(2) of this Schedule 12:

(1) where the Required Transmission Enhancement includes both new Transmission Facilities and pre-existing Transmission Facilities, cost responsibility under this section (b)(i) shall apply only to the cost of the new Transmission Facilities plus the original cost less accumulated depreciation of pre-existing Transmission Facilities that are included in Tariff, Schedule 12-Appendix or Tariff, Schedule 12-Appendix A;

(2) cost responsibility shall be assigned under this section (b)(i) only after the Required Transmission Enhancement goes into service as a Double-circuit 345 kV Required Transmission Enhancement or a Double-circuit D.C. Required Transmission Enhancement; and

(3) cost responsibility shall be assigned under this section (b)(i) for any CWIP permitted to be recovered before the Required Transmission Enhancement goes into service only after such Transmission Facilities are approved in a Regional Transmission Expansion Plan as a Double-circuit 345 kV Required Transmission Enhancement or a Double-circuit D.C. Required Transmission Enhancement.

(D) A Required Transmission Enhancement included in the Regional Transmission Expansion Plan that is a D.C. facility, consisting of D.C. lines (i.e., wires or cables) and A.C./D.C. converters, shall be a Regional Facility only if:

(1) such D.C. facility comprises two poles and operates at a voltage of ±433 kV D.C. or above; or

(2) such D.C. Facility constitutes a single Required Transmission Enhancement comprising two D.C. circuits where (i) both circuits originate from a single substation or switching station at one end and terminate at a single substation or switching station at the other end, regardless of whether or not both circuits are routed in the same right-of-way, and (ii) each such circuit consists of two poles and operates at a voltage of ±298 kV D.C or above ("Double-circuit D.C. Required Transmission Enhancement").

(ii) Lower Voltage Facilities. Transmission Provider shall assign cost responsibility for Required Transmission Enhancements that (a) are not Regional Facilities; and (b) are not "Necessary Lower Voltage Facilities" as defined in section(b)(i) of this Schedule 12 (collectively "Lower Voltage Facilities"), as follows:

(A) If the Lower Voltage Facility is a Reliability Project, Transmission Provider shall use the DFAX analysis described in subsection (b)(iii) or the analysis applicable to

Regional Facilities that address stability issues described in subsection (b)(xviii) of this Schedule 12 as applicable; and

(B) If the Lower Voltage Facility is an Economic Project, Transmission Provider shall use the methodology described in subsection (b)(v) of this Schedule 12.

(iii) DFAX Analysis for Reliability Projects.

(A) For purposes of the assignment of cost responsibility for Reliability Projects under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of this Schedule 12, the Transmission Provider, based on a computer model of the electric network and using power flow modeling software, shall calculate distribution factors, represented as decimal values or percentages, which express the portions of a transfer of energy from a defined source to a defined sink that will flow across a particular transmission facility or group of transmission facilities. These distribution factors represent a measure of the use by the load of each Zone or Merchant Transmission Facility (collectively, "Responsible Zone") of the Required Transmission Enhancement, as determined by a power flow analysis. In general, a distribution factor can be represented as:

Distribution Factor = (After-shift power flow – pre-shift power flow) / Total amount of power shifted

Total amount of power shifted = Modeled incremental megawatt transfer to a given Load Deliverability Area or Merchant Transmission Facility

Pre-shift power flow = Megawatt flow over the Required Transmission Enhancement before the incremental megawatt transfer

After-shift power flow = Megawatt flow over the Required Transmission Enhancement after the incremental megawatt transfer

When calculating such distribution factors:

(1) All distribution factors are calculated with respect to the Required Transmission Enhancement subject to cost allocation under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of this Schedule 12.

(2) The calculation of distribution factors shall be determined using linear matrix algebra, such that distribution factors represent the ratio of (i) a change in megawatt flow on a Required Transmission Enhancement to (ii) a change in megawatts transferred to aggregate load within a Zone or, in the case of a Merchant Transmission Facility, the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

(3) With respect to a Merchant Transmission Facility, zonal peak load shall mean (i) the existing Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated, if the Merchant Transmission Facility is in service, or (ii) for a

Merchant Transmission Facility that is not yet in service, the planned Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated as identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility.

(4) In the DFAX analysis, when Transmission Provider models a transfer from generation to all load within an individual Zone, Transmission Provider shall model the transfer to the Zone as a whole (not on a bus-by-bus basis).

(5) In the DFAX analysis, Transmission Provider shall model generation both external and internal to individual Responsible Zones to reflect (a) the boundaries of Locational Deliverability Areas ("LDAs"), and (b) limitations with respect to the reliability objective for moving generation capacity across the transmission system. Transmission Provider shall adopt the Capacity Emergency Transfer Objective ("CETO"), associated with that LDA and calculated for the applicable planning year to be the transfer limitation into the LDA. In modeling the system generation and load, Transmission Provider shall assume that the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA shall equal the ratio of (i) the CETO associated within that LDA (or generation internal with the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the distribution factor, Transmission Provider shall distribute these amounts of external/internal generation among all generation in the PJM Region external to/internal within the LDA, respectively, in proportion to their capacity. For Responsible Zones that are located within LDAs that are also entirely contained in other larger LDAs, the modeling approach and distribution factor calculations shall be repeated for such Responsible Zones for each LDA. The lowest distribution factor derived from these calculations shall be applied to the Responsible Zone in the calculation of the use of the Required Transmission Enhancement.

(B) The DFAX analysis will be performed in accordance with the following steps:

(1) Transmission Provider shall calculate a distribution factor and a direction of use for each Responsible Zone by modeling a transfer from all generation in the PJM Region to each Responsible Zone. To establish the use by a Responsible Zone, in megawatts, of a Required Transmission Enhancement, the distribution factor of a Required Transmission Enhancement associated with the resulting transfer modeled by the Transmission Provider to each Responsible Zone shall be multiplied by the Responsible Zone's peak load.

(2) The Transmission Provider shall separately determine the relative use of the Required Transmission Enhancement by each Responsible Zone in each direction by dividing the megawatts of use by each Responsible Zone determined in section (iii)(B)(1) above by the total use of all Responsible Zones using the Required Transmission Enhancement in the same direction of use.

(3) Transmission Provider shall determine the direction of use percentage of the Required Transmission Enhancement in each direction using a production cost analysis to determine the total use, in megawatt-hours, of the Required Transmission Enhancement by all Zones and Merchant Transmission Facilities in each direction over the course of a year. The Transmission Provider shall calculate the percentage use in each direction by dividing the megawatt-hours of use in each direction by total use in megawatt-hours in both directions of use.

(4) The Transmission Provider shall multiply the relative use by each Responsible Zone of the Required Transmission Enhancement in each direction of use determined in section (iii)(B)(2) above, by the applicable direction of use percentage determined in section (iii)(B)(3) above.

(5) The products of the calculation performed in section (iii)(B)(4) above, shall determine the relative allocation to each Responsible Zone of cost responsibility for the Required Transmission Enhancement.

(C) In the DFAX analysis, the Zones of Public Service Electric and Gas Company and Rockland Electric Company will be treated as one Zone unless and until Rockland Electric Company elects to be treated as a separate Zone in accordance with the terms of the Settlement Agreement And Offer Of Partial Settlement approved by FERC in Docket Nos. ER06-456-000, et al.

(D) Transmission Provider shall round cost responsibility assignments determined using the DFAX analysis described in subsection (b)(iii) of this Schedule 12 to the nearest one-hundredth of one percent.

(E) Transmission Provider shall not account for the ability to adjust use of phase angle regulators ("PARs") in the DFAX analysis described in subsection (b)(iii) of this Schedule 12. In the DFAX analysis, all PAR angles shall be fixed at their base case settings.

(F) In the DFAX analysis, if the Required Transmission Enhancement is a D.C. facility, the Transmission Provider shall determine cost responsibility assignment as follows:

(1) The Required Transmission Enhancement shall be replaced in the model with a comparable proxy A.C. facility, the impedance of which shall be calculated based on the length of the D.C. facility that was removed from the model multiplied by an approximate per unit/mile impedance value for the proxy A.C. facility.

(2) Where a D.C. facility is an integral part of a Required Transmission Enhancement that also includes A.C. facilities, the methodology described in subsection (b)(iii)(F)(1) above shall be used only for the D.C. facility segment of such Required Transmission Enhancement.

(3) A D.C. facility used to control flow over portions of the Transmission System shall be modeled with a zero impedance and no control shall be applied.

(G) If Transmission Provider determines in its reasonable engineering judgment that, as a result of applying the provisions in section (b)(iii) of this Schedule 12, the DFAX analysis cannot be performed or that the results of such DFAX analysis are objectively unreasonable, the Transmission Provider may use an appropriate substitute proxy for the Required Transmission Enhancement in conducting the DFAX analysis. If a proxy is used that is not specified in this Schedule 12, Transmission Provider shall state in a written report (a) the reasons why it determined the DFAX analysis could not be performed or that the results of the DFAX analysis were objectively unreasonable; (b) why the substitute proxy produced objectively reasonable results; and (3) a recommendation as to what changes, if any, should be considered in conducting the DFAX analysis.

(H) The Transmission Provider shall make a preliminary cost responsibility determination for each Required Transmission Enhancement subject to section (b)(iii) of this Schedule 12 at the time such Required Transmission Enhancement is included in the Regional Transmission Expansion Plan.

(1) When CWIP in connection with a Required Transmission Enhancement subject to this section (b)(iii) of this Schedule 12 is entitled to be recovered, the preliminary determination of cost responsibility made at the time that the Required Transmission Enhancement was included in the Regional Transmission Expansion Plan shall be used to assign cost responsibility for such CWIP and such cost responsibility shall remain unchanged until the date the Required Transmission Enhancement goes into service. Once a Required Transmission Enhancement has gone into service, the updated cost responsibility determination provided for in subsection (b)(iii)(H)(2) below shall apply.

(2) Beginning with the calendar year in which a Required Transmission Enhancement is scheduled to enter service, and thereafter annually at the beginning of each calendar year, the Transmission Provider shall update the preliminary cost responsibility determination for each Required Transmission Enhancement using the values and inputs used in the base case of the most recent Regional Transmission Expansion Plan approved by the PJM Board prior to the date of the update. All values and inputs used in the calculation of the distribution factor in a determination of cost responsibility shall be the same values and inputs as used in the base case of the most recent Regional Transmission Expansion Plan approved by the PJM Board prior to the determination of cost responsibility.

(iv) Spare Parts, Replacement Equipment And Circuit Breakers. Transmission Provider shall assign cost responsibility for spare parts, replacement equipment, and circuit breakers and associated equipment, included in the Regional Transmission Expansion Plan as follows:

(A) Spare parts that are part of the design specifications of a Required Transmission Enhancement at the time such Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required

Transmission Enhancement for the purpose of applying the cost threshold described in subsection (b)(vi) of this Schedule 12 and cost responsibility for such spare parts shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for spare parts independently included the Regional Transmission Expansion Plan and not a part of the design specifications of a Required Transmission Enhancement as described above in this subsection shall be assigned to the Zone of the owner of the spare part, if the owner of the spare part is a Transmission Owner listed in Tariff, Attachment J. If the owner of the spare part is not a Transmission Owner listed in Tariff, Attachment J, cost responsibility shall be assigned on a pro rata basis to the zones that bear cost responsibility for the owner's Required Transmission Enhancements.

(B) Replacement equipment that is part of the design specifications of a Required Transmission Enhancement at the time the Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required Transmission Enhancement for the purpose of applying the cost threshold described in section (b)(vi) of this Schedule 12 and cost responsibility for such replacement equipment shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for Required Transmission Enhancement replacement equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a Required Transmission Enhancement as described above in this subsection, shall be assigned to the same Zones and/or Merchant Transmission Facilities and in the same proportions as the then-existing assignments of cost responsibility for the facilities that the replacement equipment is replacing.

(C) Circuit breakers and associated equipment that are part of the design specifications of a Required Transmission Enhancement at the time the Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required Transmission Enhancement for the purpose of applying the cost threshold described in subsection (b)(vi) of this Schedule 12 and cost responsibility for such circuit breakers and associated equipment shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for circuit breakers and associated equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Required Transmission Enhancement as described above in this subsection, shall be assigned to the Zone of the owner of the circuit breaker and associated equipment if the owner of the circuit breaker is a Transmission Owner listed in Tariff, Attachment J. If the owner of the circuit breaker is not a Transmission Owner listed in Tariff, Attachment J, cost responsibility shall be assigned on a pro rata basis to the zones that bear cost responsibility for the owner's Required Transmission Enhancements.

(v) Economic Projects. Transmission Provider shall assign (i) fifty percent (50%) of cost responsibility for Economic Projects that are Regional Facilities; and (ii) full cost responsibility for Economic Projects that are Lower Voltage Facilities; as follows:

(A) Transmission Provider shall assign cost responsibility for Economic Projects that are accelerations of Reliability Projects as described in Operating Agreement, Schedule 6, section 1.5.7(b)(i) ("Acceleration Projects") by performing and comparing (1) a DFAX analysis consistent with the methodology described in subsection (b)(iii) of this Schedule

12, and (2) a methodology that is intended to act as a proxy for expected economic benefits from reduced Locational Marginal Prices ("LMP Benefit") over the period that the reliability-based enhancement or expansion is to be accelerated ("LMP Benefits Methodology"). The LMP Benefits Methodology shall determine cost responsibility assignment percentages to Zones and Merchant Transmission Facilities in the following manner. The LMP Benefit to a Zone shall be deemed to be equal to the reduction in Locational Marginal Price payments made by Load Serving Entities as a result of the Acceleration Project assuming the customers purchase all energy needs from the PJM Interchange Energy Market, and LMP Benefits so calculated shall be converted into percentage cost responsibility assignments for the affected Zones. The LMP Benefits Methodology shall not incorporate the financial effects of allocations of Auction Revenue Rights or Financial Transmission Rights. The LMP Benefit to a Merchant Transmission Facility shall be deemed to be equal to the proportionate share of assigned cost responsibility using the DFAX analysis and the assignments of cost responsibility to other Zones in the LMP Benefits Methodology shall be proportionately adjusted, as necessary, to reflect this treatment of Merchant Transmission Facilities to ensure that the total allocation for any economic-based Required Transmission Enhancement equals one hundred percent. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and the LMP Benefits Methodology, the results do not indicate at least a ten percentage point cost responsibility assignment differential between the two methods for any Zone, cost responsibility for the Acceleration Project shall be assigned using the DFAX analysis. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and LMP Benefits Methodology, the results indicate at least a ten percentage point cost responsibility assignment differential between the DFAX analysis and the LMP Benefits Methodology for any Zone, cost responsibility for the Acceleration Project for the period of time the Reliability Project is accelerated (i.e. the period between the date the Reliability Project actually goes into service and the date the Reliability Project originally was scheduled to go in service in the PJM Board approved Regional Transmission Expansion Plan) shall be assigned using the LMP Benefits Methodology. For all periods other than the period of time the Reliability Project is accelerated, cost responsibility for such an Acceleration Project shall be assigned in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility of Regional Facility Reliability Projects or Lower Voltage Facility Reliability Projects, as applicable.

(B) Transmission Provider shall assign cost responsibility for Economic Projects that are modifications to Reliability Projects as described in Operating Agreement, Schedule 6, section 1.5.7(b)(ii) in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility of Regional Facility Reliability Projects or Lower Voltage Facility Reliability Projects, as applicable.

(C) Transmission Provider shall assign cost responsibility for Economic Projects that are new enhancements or expansions that could relieve one or more economic constraints as described in Operating Agreement, Schedule 6, section 1.5.7(b)(iii) to the Zones that show a decrease in the net present value of the Changes in Load Energy Payment. The Change in Load Energy Payment for each year shall be determined using the methodology set forth in Operating Agreement, Schedule 6, section 1.5.7(d) for the period specified in that

section. Cost responsibility shall be assigned based on each Zone's pro rata share of the sum of the net present values of the Changes in Load Energy Payment only of the Zones in which the net present value of the Changes in Load Energy Payment shows a decrease.

(vi) Required Transmission Enhancements Costing Less Than $5 Million. Notwithstanding sections (b)(i), (b)(ii), (b)(iv), (b)(v), and (b)(xix) of this Schedule 12, cost responsibility for a Required Transmission Enhancement for which the good faith estimate of the cost of the Required Transmission Enhancement (a) prepared in connection with the development of the Regional Transmission Expansion Plan and (b) provided to the PJM Board at the time the Required Transmission Enhancement is included for the first time in the Regional Transmission Expansion Plan, does not equal or exceed $5 million shall be assigned to the Zone where the Required Transmission Enhancement is to be located. The determination of whether the estimated cost of a Required Transmission Enhancement does not equal or exceed $5 million shall be based solely on such good faith estimate of the cost of the Required Transmission Enhancement regardless of the actual costs incurred. The estimated cost of a Required Transmission Enhancement shall include the aggregate estimated costs of all of the transmission elements approved by the PJM Board at the time such elements are included in the Regional Transmission Expansion Plan that collectively are intended (i) in the case of a Reliability Project, to resolve a specific reliability criteria violation, or (ii) in the case of an Economic Project, provide a specific LMP Benefit. Where a Required Transmission Enhancement subject to this section (b)(vi) consists of a single transmission element or multiple transmission elements that will be located in more than one Zone, each Zone shall be assigned cost responsibility for the transmission elements or portions of the transmission elements located in such Zone. Merchant Transmission Facilities shall not be assigned cost responsibility for a Required Transmission Enhancement subject to this section (b)(vi).

(vii) Modifications of Required Transmission Enhancements. Once a Required Transmission Enhancement is included in the Regional Transmission Expansion Plan, any modification to such Required Transmission Enhancement that subsequently is included in the Regional Transmission Expansion Plan as a separate Reliability or Economic Project shall be considered a separate and distinct Required Transmission Enhancement for purposes of cost responsibility assignment under this Schedule 12. Except as provided in sections (b)(iv) and (b)(xiv) of this Schedule 12, any cost responsibility assignment that has been made for a previously approved Required Transmission Enhancement shall have no impact on the cost responsibility assignment of such modification.

(viii) FERC Filing. Within 30 days of the approval of each Regional Transmission Expansion Plan or an addition to such plan by the PJM Board pursuant to Operating Agreement, Schedule 6, section 1.6, the Transmission Provider shall designate in the Tariff, Schedule 12-Appendix A and in a report filed with the FERC the customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service and Merchant Transmission Facility owners that will be subject to each such Transmission Enhancement Charge ("Responsible Customers") based on the cost responsibility assignments determined pursuant to this Schedule 12. Those customers designated by the Transmission Provider as Responsible Customers shall have 30 days from the date the filing is made with the FERC to seek review of such designation. Such cost responsibility designations shall be the same as those

made for the relevant Regional Facility, Necessary Lower Voltage Facility, or Lower Voltage Facility in the Regional Transmission Expansion Plan.

(ix) Regions With Which PJM Has Entered Into an Agreement Listed in Schedule 12-Appendix B . For purposes of this Schedule 12, where costs of a Required Transmission Enhancement are allocated to a region other than PJM pursuant to an agreement set forth in Tariff, Schedule 12-Appendix B, Responsible Customers for such costs shall be customers in such region. Cost responsibility with respect to the costs of a Required Transmission Enhancements allocated to a region other than PJM shall be allocated within such region in accordance with the applicable tariff or agreement governing the allocation of such costs in such region.

(x) Merchant Transmission Facilities.

(A) For purposes of this Schedule 12, where the Transmission Provider has allocated all or a portion of a Required Transmission Enhancement to a Merchant Transmission Facility, the owner of the Merchant Transmission Facility shall be the Responsible Customer with respect to such Required Transmission Enhancement, and shall pay the Transmission Enhancement Charges associated with the Required Transmission Enhancement.

(B) (1) Transmission Provider shall defer collection of Transmission Enhancement Charges from a Merchant Transmission Facility until the Merchant Transmission Facility goes into commercial operation; provided, however, in the event the commercial operation of a Merchant Transmission Facility is delayed beyond the commercial operation milestone date(s) specified in the Interconnection Service Agreement associated with the Merchant Transmission Facility and the Transmission Provider or Transmission Owner constructing the Required Transmission Enhancement demonstrates that the Merchant Transmission Facility is responsible for such delay, Transmission Provider may begin collecting Transmission Enhancement Charges from the Merchant Transmission Facility prior to the Merchant Transmission Facility going into commercial operation. Transmission Enhancement Charges allocated to a Merchant Transmission Facility for which collection is deferred in accordance with this section (b)(x)(B)(1) shall be recorded in appropriate Transmission Provider accounts for deferred charges and collected in accordance with section (b)(x)(B)(3) below.

(2) Transmission Provider shall base the collection of Transmission Enhancement Charges associated with Required Transmission Enhancements from a Merchant Transmission Facility on the actual Firm Transmission Withdrawal Rights that have been awarded to the Merchant Transmission Facility; provided, however, to the extent that a Merchant Transmission Facility has been awarded less than the amount of Firm Transmission Withdrawal Rights specified in the Interconnection Service Agreement associated with the Merchant Transmission Facility, then Transmission Provider shall record the difference between the amount of Transmission Enhancement Charges collected based on the lesser amount of Firm Transmission Withdrawal Rights and the amount of Transmission Enhancement Charges based on the full amount of Firm Transmission Withdrawal Rights specified in the applicable Interconnection Service Agreement in appropriate accounts for deferred charges and, after the Merchant Transmission Facility has been awarded the full amount of Firm Transmission

Withdrawal Rights specified in the Interconnection Service Agreement, collect such deferred amounts in accordance with section (b)(x)(B)(3) below. Notwithstanding the foregoing, Transmission Provider may collect Transmission Enhancement Charges based on more than a Merchant Transmission Facility's actually awarded Firm Transmission Withdrawal Rights (not to exceed the Firm Transmission Withdrawal Rights specified in the applicable Interconnection Service Agreement) if the Transmission Provider or Transmission Owner demonstrates that the Merchant Transmission Facility is responsible for receiving fewer Firm Transmission Withdrawal Rights than are specified in the applicable Interconnection Service Agreement.

(3) Transmission Provider shall record: (i) in an appropriate deferred asset account, the Transmission Enhancement Charges associated with Required Transmission Enhancements for which collection is deferred in accordance with sections (b)(x)(B)(1) and (b)(x)(B)(2) above; and (ii) in an appropriate deferred liability account, the revenues associated with the Transmission Enhancement Charges that, absent the deferred charges, would have been due to Transmission Owners or to Transmission Owners' customers as directed by the applicable Transmission Owner. At such time as collection of such deferred Transmission Enhancement Charges are permitted in accordance with sections (b)(x)(B)(1) and (b)(x)(B)(2) above, the deferred charges (along with appropriate interest) shall be collected from the Merchant Transmission Facility in equal installments over the twelve months following the commencement of the collection of the deferred charges. Such amounts shall be distributed to Transmission Owners or to Transmission Owners' customers as directed by the applicable Transmission Owner, and the Transmission Provider shall make appropriate adjustments to the deferred asset and liability accounts. Transmission Provider shall not be responsible for distributing revenues associated with deferred Transmission Enhancement Charges unless and until such charges are collected in accordance with this section (b)(x)(B), and uncollected deferred Transmission Enhancement Charges shall not be subject to Default Allocation Assessments to the Members pursuant to Operating Agreement, section 15.2.

(xi) Consolidated Edison Company of New York. (A) Cost responsibility assignments to Consolidated Edison Company of New York for Required Transmission Enhancements pursuant to this Schedule 12 with respect to the Firm Point-To-Point Service Agreements designated as Original Service Agreement No. 1873 and Original Service Agreement No. 1874 accepted by the Commission in Docket No. ER08-858 ("ConEd Service Agreements") shall be in accordance with the terms and conditions of the settlement approved by the FERC in Docket No. ER08-858-000. (B) All cost responsibility assignments for Required Transmission Enhancements pursuant to this Schedule 12 shall be adjusted at the commencement and termination of service under the ConEd Service Agreements to take account of the assignments under subsection (xi)(A) of this section.

(xii) Public Policy Projects.

(A) Transmission Facilities as defined in Consolidated Transmission Owners Agreement, section 1.27 constructed by a Transmission Owner pursuant to a Public Policy Requirement but not included in a Regional Transmission Expansion Plan as a Required Transmission Enhancement, shall be as considered a Supplemental Project.

(B) If a transmission enhancement or expansion is proposed pursuant to Operating Agreement, Schedule 6, section 1.5.9(a) which is not a Supplemental Project ("State Agreement Public Policy Project"), the Transmission Provider shall submit the assignment of costs to Responsible Customers proposed in connection with such State Agreement Public Policy Project to the Transmission Owners Agreement Administrative Committee for consideration and filing pursuant to Consolidated Transmission Owners Agreement, section 7.3 and Tariff, Part I, section 9.1(a). Nothing in this section (b)(xii) shall prevent the Transmission Provider or the state governmental entities proposing such State Agreement Public Policy Project from filing a proposed assignment of costs to Responsible Customers for such project pursuant to Section 206 of the Federal Power Act.

(xiii) Replacement of Transmission Facilities. Unless determined by PJM to be a Required Transmission Enhancement included in a Regional Transmission Expansion Plan, cost responsibility for the replacement of Transmission Facilities, as defined in Consolidated Transmission Owners Agreement, section 1.27, shall be assigned to the Zonal loads and Merchant Transmission Facilities responsible for the costs of the Transmission Facilities being replaced.

(xiv) Multi-Driver Projects.

(A) Assignment of Proportional Multi-Driver Project Costs. The Transmission Provider shall assign cost responsibility for Proportional Multi-Driver Projects in proportion to the relative percentage benefit that each driver of a Proportional Multi-Driver Project addresses, respectively, reliability violations or operational performance ("reliability"), economic constraints ("economic") and/or Public Policy Requirements ("public policy") as follows:

(1) As part of the open planning process provided for in Operating Agreement, Schedule 6, section 1.5.10(h), the Transmission Provider employs the Proportional Method to develop a Proportional Multi-Driver Project, by determining which of the following drivers a Proportional Multi-Driver Project addresses: reliability, economic, or public policy, and the extent to which each such driver contributes to the size, scope, and estimated costs of such Proportional Multi-Driver Project (irrespective of the reliability cost allocation treatment that is otherwise accorded an incremental market efficiency modification thereto pursuant to section (b)(v)(B) of this Schedule 12). The Transmission Provider shall identify the contribution of each driver in terms of a percentage totaling 100 percent for all such drivers at the time that each Proportional Multi-Driver Project is submitted to the PJM Board for approval and included in the Regional Transmission Expansion Plan. The percentage contribution of each driver shall be based on the ratio of the estimated cost of each project that the Multi-Driver Project replaces to the total of the estimated costs of all projects combined into the Multi-Driver Project.

(2) Once a Proportional Multi-Driver Project is approved by the PJM Board, the percentage contributions of each driver shall not be changed unless the PJM Board subsequently approves an upgrade or modification to the Proportional Multi-Driver

Project. In that event, the cost responsibility for the Proportional Multi-Driver Project, including any costs incurred prior to the upgrade or modification, will be determined as if it were a new Proportional Multi-Driver Project, such that the percentage contribution for each driver shall be established anew.

(B) Assignment of Incremental Multi-Driver Project Costs. The Transmission Provider shall assign cost responsibility for Incremental Multi-Driver Projects as defined in Operating Agreement, Schedule 6, section 1.15B using the same methodology described in section (b)(xiv)(A)(1) above treating the estimated cost of modifying the original project as if it were the estimated cost of a separate project included in a Proportional Multi-Driver Project. Any costs that had been expended on the original project prior its designation by Transmission Provider as an Incremental Multi-Driver Project shall be included in the calculation of the Incremental Multi-Driver Project pursuant to this section (b)(xiv)(B).

(C) The Transmission Provider shall separately assign cost responsibility for the costs assigned to each driver pursuant to this section (b)(xiv) in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility for a single driver project of each driver's respective type (reliability, economic or public policy). Except as provided in section (b)(xiv)(D) below, cost responsibility will be assigned based on the final voltage and configuration of the Multi-Driver Project determined in accordance with sections (b)(i), (b)(ii), or (b)(vi) of this Schedule 12.

(D) Notwithstanding the cost assignments that would otherwise be provided for in section (b)(xiv)(C) above, if a Multi-Driver Project includes a public policy driver that is the result of the State Agreement Approach provided for in Operating Agreement, Schedule 6, section 1.5.9 and is a Regional Facility as defined in section (b)(i) of this Schedule 12 and such Multi-Driver Project would not be a Regional Facility but for the inclusion of the public policy driver, then the percentage of costs of such Multi-Driver Project assigned to the non-public policy drivers in accordance with the procedures set forth in in section (b)(i)(A)(1) above shall be twenty percent (20%) and the percentage of costs assigned to the non-public policy drivers of such Multi-Driver Project in accordance section (b)(i)(A)(2) above shall be eighty percent (80%), and not the fifty percent (50%) cost responsibility percentages provided for in section (b)(i)(A)(i) and section (b)(i)(A)(2), respectively, of this Schedule 12.

(xv) ***Reserved.***

(xvi) Required Transmission Enhancements Designed to Address Reliability Violations on Transmission Facilities Operating Below 200 kV. Notwithstanding section (b)(ii), above, cost responsibility for any Required Transmission Enhancements that are included in the Regional Transmission Expansion Plan to address reliability violations on Transmission Facilities that are designed to operate at below 200 kV and, pursuant to Operating Agreement, Schedule 6, section 1.5.8(n), were not included in an Operating Agreement, Schedule 6, section 1.5.8(c) proposal window, shall be assigned to the Responsible Customers in the Zone where the Required Transmission Enhancement is to be located.

(xvii) Required Transmission Enhancements Constructed As Targeted Market Efficiency Projects Under The Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. Coordinated System Plan. Notwithstanding sections (b)(i), (b)(ii), (b)(iv), (b)(v), (b)(vi) and (b)(x)(B)(2) of this Schedule 12, cost responsibility for the costs of a Required Transmission Enhancement that is included in the Regional Transmission Expansion Plan because it is a Targeted Market Efficiency Project ("TMEP") identified in the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. ("PJM-MISO JOA") and assigned to PJM pursuant to PJM-MISO JOA, section 9.4.4.2.5, shall be assigned among Zones and Merchant Transmission Facilities in accordance with this section (b)(xvii). Using the Targeted Market Efficiency Project study conducted pursuant to PJM-MISO JOA, section 9.3.7.2(c) of in which the TMEP was identified, the Transmission Provider shall determine, in accordance with Tariff, Attachment K-Appendix, section 5.1, the average annual Transmission Congestion Charges experienced by Market Buyers in Zones and at Merchant Transmission Facilities attributable to the targeted Reciprocal Coordinated Flowgate during the two historical calendar years prior to the study year of the Targeted Market Efficiency Project study. In making this determination, the Transmission Provider shall net any increases in Day-ahead and Real-time Prices paid by Market Buyers in a Zone or at a Merchant Transmission Facility against any decreases in Day-ahead and Real-time Prices paid by Market Buyers in such Zone or at such Merchant Transmission Facility attributable to the targeted Reciprocal Coordinated Flowgate. Where a single TMEP is constructed to reduce Transmission Congestion Charges attributable to more than one targeted Reciprocal Coordinated Flowgate, the Transmission Provider shall net any increases in Day-ahead and Real-time Prices paid by Market Buyers in a Zone or at a Merchant Transmission Facility against any decreases in Day-ahead and Real-time Prices paid by Market Buyers in such Zone or at such Merchant Transmission Facility attributable to all targeted Reciprocal Coordinated Flowgates. Cost responsibility shall be assigned based on each Zone's and Merchant Transmission Facility's pro rata share of the sum of the net Transmission Congestion Charges paid by Market Buyers only of the Zones and Merchant Transmission Facilities in which Market Buyers experienced net Transmission Congestion Charges.

(xviii) Required Transmission Enhancements Designed to Address Stability Issues. For purposes of the assignment of cost responsibility for Reliability Projects designed to address stability issues under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of this Schedule 12, the Transmission Provider shall, using the same inputs and assumptions from the simulation that originally drove the need for the stability upgrade, perform a stability simulation that includes the stability upgrade under the worst fault condition. The worst fault condition shall be the fault condition in the simulation that produces the maximum rotor angle swing with the stability upgrade included. For each load bus on the system, the difference between the highest and lowest voltage angle that occurs during the simulation of the worst fault condition will be recorded. Load buses having a voltage angle deviation less than 25 percent of the load bus with the largest voltage angle deviation will not be included in the cost allocation calculation. For the remaining load buses, the voltage angle deviation will be multiplied by the megawatt load at the bus obtained from the stability simulation model, or, in the case of a Merchant Transmission Facility, the Firm Transmission Withdrawal Rights at the bus. The products of the voltage angle deviation and megawatt load at each bus will be summed for each Responsible Zone. The

Stability Deviation cost allocation for a Responsible Zone or Merchant Transmission Facility will be determined by dividing the sum of the load-weighted angle deviations for the Responsible Zone or Merchant Transmission Facility by the sum of the load-weighted angle deviations for each Responsible Zone and Merchant Transmission Facility. Transmission Provider shall round cost responsibility assignments to the nearest one-hundredth of one percent.

(xix) Regional Facilities and Necessary Lower Voltage Facilities Included in the Long-Term Regional Transmission Plan. The Transmission Provider shall assign cost responsibility for Required Transmission Enhancements included in the Long-Term Regional Transmission Plan in accordance with section (b) of this Schedule 12, as applicable, except as set forth in this section (b)(xix):

(A) Cost responsibility for all Regional Facilities and Necessary Lower Voltage Facilities included in the Long-Term Regional Transmission Plan solely to address Core LT Needs shall be allocated among Responsible Customers as defined in this Schedule 12 as follows:

(1) Fifty percent (50%) shall be assigned annually in accordance with section (b)(i)(A)(1)(a) or (b)(i)(A)(1)(b) of this Schedule 12, as applicable, and

(2) Fifty percent (50%) shall be assigned in accordance with section (b)(iii) of this Schedule 12.

(B) Cost responsibility for all Regional Facilities and Necessary Lower Voltage Facilities included in the Long-Term Regional Transmission Plan solely to address Additional LT Needs shall be allocated among Responsible Customers as defined in this Schedule 12 as follows:

(1) Fifteen percent (15%) shall be assigned annually in accordance with section (b)(i)(A)(1)(a) or (b)(i)(A)(1)(b) of this Schedule 12, as applicable, and

(2) Eighty-five percent (85%) shall be assigned in accordance with section (b)(iii) of this Schedule 12.

(C) (1) Cost responsibility for a Required Transmission Enhancement that is a Regional Facility or a Necessary Lower Voltage Facility included in the Long-Term Regional Transmission Plan to address both Core LT Needs and Additional LT Needs shall be assigned to Responsible Customers as defined in this Schedule 12 as follows:

(a) The costs of facilities that would be required to address only the Core LT Needs addressed by such Required Transmission Enhancement shall be assigned in accordance with section (xix)(A). The cost of facilities that would be required to address only the Core LT Needs addressed by such Required Transmission Enhancement shall be determined by the cost of such facilities included in the Core Plan; and

(b) The cost of the facilities required to address the Additional LT Needs addressed by such Required Transmission Enhancement shall be assigned in accordance with section (xix)(B). The Transmission Provider shall determine the cost of the facilities required

to address the Additional LT Needs addressed by such Required Transmission Enhancement at the time the PJM Board approves such Required Transmission Enhancement for inclusion in the Long-Term Regional Transmission Plan pursuant to Operating Agreement, Schedule 6-C, section 1.17(a) by subtracting the cost determined pursuant to section (b)(xix)(C)(1)(a) from the total cost of such Required Transmission Enhancement. Such determination shall be used to determine the percentage of the annual revenue requirement assigned pursuant to section (b)(xix)(A) and (b)(xix)(B), respectively.

(2) Cost responsibility for a Required Transmission Enhancement that is a Lower Voltage Facility included in the Long-Term Regional Transmission Plan to address either Core LT Needs or Additional LT Needs or both shall be assigned to Responsible Customers as defined in this Schedule 12 in accordance with section (b)(iii) of this Schedule 12.

(D) If a Voluntary Funding Entity proposes a Voluntary Funding Agreement pursuant to Operating Agreement, Schedule 6-C, section 1.14 (Voluntary Funding for Long-Term Transmission Project(s) Addressing Additional LT Needs) to assign the cost of a Required Transmission Enhancement included in the All-in-One Plan to Responsible Customers, the Transmission Provider shall submit such assignment of costs to the Transmission Owners Agreement Administrative Committee for consideration and filing pursuant to Consolidated Transmission Owners Agreement, section 7.3 and Tariff, Part I, section 9.1(a). Nothing in this section (b)(xix)(D) shall prevent the Transmission Provider or such Voluntary Funding Entity from filing a proposed assignment of costs to Responsible Customers for such Required Transmission Enhancement pursuant to Section 206 of the Federal Power Act. If approved by the Commission, the assignment of costs of such Required Transmission Enhancement to Responsible Customers under such Voluntary Funding Agreement shall supersede any such assignment pursuant to section (b)(xix)(B) or (b)(xix)(C)(1)(b) as applicable.

(E) If within six months following the approval of a Long-Term Regional Transmission Plan, the PJM Area Relevant State Entities Committee members agree pursuant to a State Agreement Process they have adopted to a State Cost Assignment Agreement to assign the costs of a Required Transmission Enhancement included in the Long-Term Regional Transmission Plan to Responsible Customers and provide such State Cost Assignment Agreement to the Transmission Provider, the Transmission Provider shall submit such proposed assignment of costs to the Transmission Owners Agreement Administrative Committee for consideration and filing pursuant to Consolidated Transmission Owners Agreement, section 7.3 and Tariff, Part I, section 9.1(a). Nothing in this section (b)(xix)(E) shall prevent the Transmission Provider or the PJM Area Relevant State Entities Committee from filing a proposed assignment of costs to Responsible Customers for such Required Transmission Enhancement pursuant to Section 206 of the Federal Power Act. If such assignment of costs is approved by the Commission, the assignment of costs of such Required Transmission Enhancement to Responsible Customers shall supersede any such assignment pursuant to section (b)(xix)(A), (b)(xix)(B) or (b)(xix)(C)(1) as applicable.

(F) If an agreement under either section (b)(xix)(D) or (b)(xix)(E) is approved by the Commission requiring the assignment of cost responsibility for a Required Transmission Enhancement included in the Long-Term Regional Transmission Plan to Responsible Customers within the borders of certain states that are part of a multi-state Zone and neither such agreement

nor other agreement approved or accepted by the Commission or the relevant authorities in such states identifies the Responsible Customers in each state, the Transmission Provider shall identify the Responsible Customers according to the following formula:

CS=(ASPL/AZPL) x CRTE

Where:

CS is the total cost assigned to Responsible Customers within a state or portion thereof that is part of a multi-state Zone

ASPL is the load of Responsible Customers in a state or portion thereof that is part of a multi-state zone coincident with the annual zonal peak load determined pursuant to section (b)(i)(A)(1)(A)

AZPL is the zonal peak load determined pursuant to section (b)(i)(A)(1)(A)

CRTE is the annual revenue requirement of the Required Transmission Enhancement

The total cost of a Required Transmission Enhancement assigned to Responsible Customers within a state shall be assigned to individual Responsible Customers based on the applicable methodology utilized in such state or Zone to assign costs to Responsible Customers. Nothing in this Schedule 12 shall authorize the Transmission Provider to assign the cost of Required Transmission Enhancements to Responsible Customers based on the state in which such Responsible Customers are located, except as required as a result of an agreement under section (b)(xix)(D) or (b)(xix)(E).

(G) The Transmission Owners Agreement Administrative Committee shall consult with the PJM Area Relevant State Entities Committee with respect to any proposed amendments to this section (b)(xix) of Schedule 12 as follows:

(1) No less than 30 days prior to any Section 205 filing by the Transmission Owners Agreement Administrative Committee; and

(2) No less than 30 days after receipt of a notice addressed to the Chair of the Administrative Committee that the PJM Area Relevant State Entities Committee have agreed to request the Transmission Owners Agreement Administrative Committee to make a Section 205 filing.

Following any consultation under this section (G), the Transmission Owners Agreement Administrative Committee shall post on the PJM Website the results of such consultation with the PJM Area Relevant State Entities Committee. If the Transmission Owners Agreement Administrative Committee initiated the consultation, such posting shall be made prior to filing their proposed amendment to this section (b)(xix). If the PJM Area Relevant State Entities Committee initiated the consultation and the Transmission Owners Agreement Administrative Committee declined to file an amendment to this section (b)(xix) pursuant to Consolidated

Transmission Owners Agreement, section 7.3 and Tariff, Part I, section 9.1(a), the Transmission Owners Agreement Administrative Committee shall post on the PJM Website the results of such consultation with PJM Area Relevant State Entities Committee, including an explanation for why it has declined to propose any amendments. Nothing in this section (b)(xix)(G) shall prevent the Transmission Provider or the PJM Area Relevant State Entities Committee from filing a proposed amendment to this section (b)(xix) pursuant to Section 206 of the Federal Power Act.

(c) Determination of Transmission Enhancement Charges. In the event that any Transmission Owner recovers the cost of a Required Transmission Enhancement through a Transmission Enhancement Charge, such charge shall be determined as follows:

(1) Transmission Provider shall identify in writing and post on the PJM Internet site the Required Transmission Enhancement(s) to which each Transmission Enhancement Charge corresponds. The Transmission Enhancement Charge with respect to a Required Transmission Enhancement shall recover the applicable Transmission Owner's annual transmission revenue requirement associated with the Required Transmission Enhancement.

(2) Each Transmission Enhancement Charge shall be a monthly charge based on all costs and applicable incentives associated with a particular Required Transmission Enhancement for which the Transmission Owner is responsible.

(3) A Transmission Owner's annual transmission revenue requirement associated with a Required Transmission Enhancement shall be determined pursuant to either (i) a unilateral filing by the Transmission Owner under Section 205 of the Federal Power Act and the FERC's rules and regulations thereunder; or (ii) a formula rate in effect applicable to the Transmission Owner's rates for Network Integration Transmission Service, including the costs associated with Required Transmission Enhancements.

(4) Each Transmission Enhancement Charge applicable to Network Customers and Non-Zone Network Customers shall be recalculated annually to reflect the annual revisions to the billing determinants used by the Transmission Provider to calculate charges to Network Customers for Network Integration Transmission Service under Tariff, Part III, section 34.1. The Transmission Provider shall post on its Internet site by October 31 of each calendar year each recalculated Transmission Enhancement Charge that shall be effective during the subsequent calendar year.

(5) Each Transmission Enhancement Charge applicable to customers using Point-To-Point Transmission Service shall be calculated monthly to reflect the billing determinants used by the Transmission Provider to determine charges for customers of Point-To-Point Transmission Service in accordance with Tariff, Part II, section 25.

(6) Each Transmission Enhancement Charge payable by an owner of a Merchant Transmission Facility pursuant to section (b) of this Schedule 12 shall be calculated as a fixed monthly charge.

(7) If a Transmission Owner chooses to recover the cost of Required Transmission Enhancements through the operation of a formula rate as described in section (a) of this Schedule 12, the Transmission Owner must make an informational filing with the Commission one year from the date the selecting Transmission Owner's formula rates go into effect, and each year thereafter, providing a detailed list of the costs the Transmission Owner has incurred, and the revenues the Transmission Owner has received to provide service.

(d) Recovery of Transmission Enhancement Charges.

(1) Responsible Customers shall pay Transmission Provider all applicable Transmission Enhancement Charges as required by this Schedule 12 in addition to all other charges for transmission service for which such Responsible Customers are responsible under the Tariff.

(2) Transmission Provider shall collect all applicable Transmission Enhancement Charges from each Responsible Customer on a monthly basis. Transmission Provider shall remit or credit all revenues received from Responsible Customers under this Schedule 12 to the Transmission Owner(s) that established such charge or to the appropriate authority in a region other than PJM in the case of Transmission Enhancement Charges established in such region in connection with a Required Transmission Enhancement constructed pursuant to an Appendix B Agreement, to be distributed in accordance with the applicable tariff or agreement governing the distribution of such charges in such region.

(e) Crediting of Revenue from Transmission Enhancement Charges. In recognition that a Transmission Owner's charges for Network Integration Transmission Service set forth in Tariff, Attachment H are established based upon the Transmission Owner's total cost of providing FERC-jurisdictional transmission service, including the costs associated with Required Transmission Enhancements, revenue from a Transmission Owner's Transmission Enhancement Charges for a billing month shall be credited pursuant to this Schedule 12 to the Network Customers in the Transmission Owner's Zone (including, where applicable, the Transmission Owner) and Transmission Customers purchasing Firm Point-to-Point Transmission Service for delivery in the Transmission Owner's Zone in proportion to their Demand Charges (including any imputed Demand Charges for bundled service to Native Load Customers) for Network Integration Transmission Service and Reserved Capacity for Firm Point-to-Point Transmission Service; provided that such credits shall be reduced by the amount of any applicable incentives included in such Transmission Enhancement Charges.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ATTACHMENT C

DECLARATION OF AMBER THOMAS

I. INTRODUCTION

1. My name is Amber Thomas. I am the Senior Manager of Transmission Strategy at Exelon Business Services Company, a subsidiary of Exelon Corporation ("Exelon"). I have been in this role since November 2024. My current responsibilities include managing the team that develops, advocates, and implements energy policy across the Exelon services territories such as Delaware, Illinois, Maryland, New Jersey, Pennsylvania and the District of Columbia. In this role where I am primarily focused on the PJM region, I have the responsibility for the development of energy policy matters such as wholesale transmission rate design and recovery, transmission planning, generation/load interconnections, and best practices across the industry.

2. My career spans over 17 years, during which I have primarily been responsible for policy development and transmission planning activities. Over this period, I have held various roles including Senior Manager of Transmission Regional Planning within Exelon, where I was responsible for leading a team of engineers and analysts who were tasked with transmission planning analysis and development of transmission infrastructure to support reliability, large load interconnections, and generation projects. Before joining Exelon, I held the role of Senior Transmission Regulatory & Rates Specialist at PPL, and Senior Engineer in Transmission Planning at PJM Interconnection. I have previously submitted testimony at the state public utility commissions for the states of Virginia, Maryland, and Pennsylvania.

3. I am submitting this Declaration in support of the PJM Transmission Owners' ("Transmission Owners") filing of amendments to the PJM Tariff to comply with the cost allocation requirements of Order No. 1920.[1] The Transmission Owners developed the proposed tariff amendments after nearly twenty-four months of collaboration and coordination with PJM, the PARSEC, and among ourselves. The TOAAC approved these proposed tariff provisions on November 12, 2026.

4. In this Declaration, I first describe the Engagement Period between the Transmission Owners and the Relevant State Entities in the PJM region, who, under the Organization

[1] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024) ("Order No. 1920"). All defined terms in this Declaration shall have the meaning set forth in the PJM Open Access Transmission Tariff, the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., or Order No. 1920, as applicable.

of PJM States ("OPSI"), organized as the PJM Area Relevant State Entities Committee ("PARSEC") for the purpose of Order No. 1920 compliance.

5. I then describe the efforts that the Transmission Owners made to collaborate and negotiate with the PARSEC to try to reach agreement on a cost allocation proposal, including our efforts to incorporate state feedback and interests into our cost allocation proposal.

II. ENGAGEMENT PERIOD

6. The Engagement Period for the PJM region formally began on October 7, 2024, when the Transmission Owners hosted the first virtual meeting with the PARSEC members. Prior to this date, at least one Transmission Owner operating in each state in the PJM region solicited contact information from their contacts at state agencies so that the Transmission Owners could compile a service list of Relevant State Entities for the Engagement Period. We also held a virtual kickoff meeting on September 9, 2024 with OPSI leadership to announce the Engagement Period and discuss how we can properly implement a robust Engagement Period. We also learned from OPSI leadership that the Relevant State Agencies were organizing into the PARSEC.

7. Thus, by October 7, the Transmission Owners had created a service list of PARSEC members and its leadership. Transmission Owners' counsel maintained the list and updated it with new requests from PARSEC and Transmission Owner members periodically. Throughout the Engagement Period, the Transmission Owners used this service list to distribute meeting invitations and other information.

8. Over the Engagement Period, full group meetings between the Transmission Owners and the PARSEC members occurred on the dates listed below. PJM often joined these meetings as well.

    a. October 7, 2024

    b. November 4, 2024

    c. December 2, 2024

    d. February 3, 2025

    e. March 3, 2025

    f. April 21, 2025

    g. May 5, 2025

    h. June 2, 2025

    i. July 7, 2025

j. August 18, 2025

k. October 20, 2025

l. December 15, 2025

m. March 16, 2026

n. March 30, 2026

Additionally, individual Transmission Owners and the Transmission Owners' counsel informally met with members from PARSEC and their staff throughout this Engagement Period.

9. On October 7, 2024, at the Transmission Owners' request, PJM posted notice on the PJM website that the Engagement Period had begun. This notice also included the deadline—initially April 14, 2025—for the states to communicate their proposal to the Transmission Owners and the contact information for our counsel to whom the states should communicate such a proposal.

10. At the October 7 meeting, the Transmission Owners and the PARSEC discussed a plan to meet on a monthly basis, generally on the first Monday of each month from 11:00 AM to 1:00 PM.

11. The first few Engagement Period meetings focused on education about cost allocation methodologies. The Transmission Owners briefed PARSEC on key legal precedents that underpin the Commission's transmission cost allocation requirements and covered the various cost allocation methodologies used in PJM and in other regions. We understood that, by providing this education, it would be helpful in, not only providing the historical context in which cost allocation methodologies have been developed, refined, and adopted across several decades, but also provide a foundation for developing a cost allocation with the PARSEC for projects developed under Order No. 1920 planning.

12. In the fall of 2024, based in part on these meetings with PARSEC, the Transmission Owners also met regularly to discuss their own ideas and perspectives on developing a cost allocation methodology for Order No. 1920. At this time, the compliance deadline was June 12, 2025, and we knew this would not allow sufficient time to develop a consensus within each group and to negotiate with the PARSEC. Thus, in early 2025, PJM, the Transmission Owners, and the PARSEC agreed to request an extension on the compliance filing deadline and on the Engagement Period. The Commission granted the extension on February 6, 2025. This extended the Engagement Period to October 7, 2025, and extended the deadline for PARSEC to communicate agreement to October 14, 2025. The deadline for the compliance filing was extended until December 12, 2025.

13. During the Engagement Period, the Transmission Owners and the PARSEC both recognized that any cost allocation for Order No. 1920 projects would need to work

seamlessly with the long-term regional transmission planning ("LTRTP") protocol that PJM was developing for Order No. 1920 planning compliance. Thus, in the spring of 2025, when PJM first began to share the LTRTP protocol it was developing, the Transmission Owners and the PARSEC turned their attention to discussing, understanding, and providing feedback on PJM's LTRTP protocol and discussing how a potential cost allocation could work within the proposed planning framework. This continued throughout the summer and early fall 2025, as PJM was finalizing its plan.

14. By September 2025, the Transmission Owners and the PARSEC agreed that we would not be able to develop cost allocation proposals by December 2025. We agreed it would be more productive to develop and finalize a cost allocation for Order No. 1920 projects after PJM's LTRTP proposal was finalized, which was scheduled to be filed in December 2025. Thus, the Transmission Owners and PARSEC requested another extension of the compliance filing deadline and Engagement Period, to June 12, 2026. The Commission granted this extension on October 17, 2025. This extended the Engagement Period to April 7, 2026 and extended the deadline for PARSEC to communicate agreement to April 14, 2026.

15. Beginning in October 2025, the Transmission Owners and the PARSEC paused our monthly meetings and instead held meetings on an as-needed basis so that each group could focus on its own discussions to develop cost allocation proposals.

16. While the Transmission Owners and PARSEC did not reach agreement by April 14, both groups believed that further discussion would be productive in reaching an agreement on cost allocation. Thus, on June 4, 2026, the Transmission Owners and PARSEC asked the Commission for further extension of time to file the compliance filing and to engage with DRS Staff in a further attempt to reach resolution. The Commission made the DRS available to the Transmission Owners and PARSEC on June 11, 2026, and the two parties engaged in those services. The Transmission Owners and PARSEC requested extensions of the compliance filing deadline two more times, on August 4, 2026; and September 8, 2026.

17. Despite an extensive effort by both the PARSEC and the PJM Transmission Owners, agreement could not ultimately be reached on a cost allocation. Thus, on September 8, 2026, the Transmission Owners and PARSEC jointly sought to file a Motion to Govern future proceedings in which they would set the compliance filing deadline, which the Commission approved on September 15, 2026.

18. During this prolonged engagement period, the Transmission Owners adjusted their proposals several times, in an effort to address interests and concerns expressed by the states.

19. The Engagement Period ended on September 25, 2026, when the Transmission Owners jointly filed their Motion to Govern, reporting that the Transmission Owners and PARSEC had not reached agreement and setting the compliance filing deadline for November 19, 2026. The Commission approved the Transmission Owners' Motion to Govern on October 8, 2026.

III. TRANSMISSION OWNERS' EFFORTS TO NEGOTIATE WITH AND RESPOND TO PARSEC'S INTERESTS

20. The Transmission Owners' goal for the Engagement Period was to reach agreement with the PARSEC on a cost allocation. That goal was at the forefront of our internal discussions to develop a cost allocation proposal. This led the Transmission Owners to develop a cost allocation proposal that was designed to reach consensus with the PARSEC on many key components based on our understanding of features that were of interest to the PARSEC. These are reflected in the Transmission Owners' proposed Tariff changes. We also included provisions that would facilitate the State Agreement Process required by Order No. 1920, such as a way to identify cost assignments for single states, even if those states are within a multi-state zone for the purpose of PJM's benefit analysis.

21. As described above, the Transmission Owners and PARSEC continued discussions for nearly two years. The parties also engaged DRS Staff to assist with the negotiations and held several meetings with the assistance of DRS Staff. However, we ultimately were not able to reach agreement on all elements of the cost allocation framework despite our extended Engagement Period. While we did not reach agreement, through those extensive discussions, the Transmission Owners gained an understanding of the perspectives of the states. As such, we have tried to craft a cost allocation that balances that feedback with the objectives of the Commission in Order No. 1920 in effectuating a forward-looking, scenario-based planning process that will achieve identification and development of beneficial regional transmission infrastructure.

22. On November 16, 2026, PARSEC shared their proposal and requested that the Transmission Owners include these materials as an attachment to the Transmission Owners' Order No. 1920 compliance filing per the Commission's directive that we do so. The Transmission Owners have done so here under protest.

IV. CONCLUSION

23. In sum, the Transmission Owners educated, listened, collaborated, coordinated, and negotiated with the PARSEC during this nearly 24-month Engagement Period. Although the Transmission Owners' goal was to reach agreement with the PARSEC on a consensus cost allocation proposal, the Transmission Owners discharged their Order 1920 compliance obligations and developed a backstop cost allocation proposal. In doing so, the Transmission Owners incorporated cost allocation concepts and interests that emerged from our engagement with the PARSEC.

24. This concludes my Declaration.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed this 19th day of November, 2026.



Amber Thomas

November 19, 2026

Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: PJM Interconnection, L.L.C., Docket No. ER27-_____-000
PARSEC Agreement on Long-Term Regional Transmission Cost Allocation Methods and State Agreement Process

Dear Secretary Reese:

Order No. 1920 long-term regional transmission planning differs materially from near-term reliability planning and therefore requires a cost allocation method that departs significantly from the status quo. The PJM Area Relevant State Entities Committee ("PARSEC") requests the Federal Energy Regulatory Commission ("Commission" or "FERC") find that the PARSEC Agreement on Long-Term Regional Transmission Cost Allocation Methods and a State Agreement Process, attached as Appendix A, represents a just and reasonable approach to allocating the costs of Long-Term Regional Transmission ("LTRT") Facilities and direct PJM Interconnection, L.L.C. ("PJM") and the PJM Transmission Owners ("TOs") to provide the Commission with compliance filings to implement it. PARSEC's Agreement is both just and reasonable and preferable to the TOs' approach, which is not just and reasonable because it relies on the exact same cost allocation method for Core Long-Term ("LT") projects,[1] as is used for near-term reliability projects, despite the fact the Order No. 1920 planning process is fundamentally different from near-term reliability planning.[2]

[1] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order No. 1920, 187 FERC ¶ 61,068, at PP 250, 344–347 (2024) ("Order 1920") (defining Long-Term Regional Transmission Facilities and requiring a planning horizon of at least 20 years from the start of the planning cycle).

[2] PARSEC entered into this Agreement on November 13, 2026, pursuant to its Charter. The following PARSEC members support this Agreement: the Delaware Public Service Commission, Delaware State Energy Office, Public Service Commission of the District of Columbia, Indiana Utility Regulatory Commission, Kentucky Public Service Commission, Kentucky State Board on Electric Generation and Transmission Siting, Maryland Public Service Commission, Michigan Public Service Commission, New Jersey Board of Public Utilities, New Jersey Department of Environmental Protection, North Carolina Utilities Commission, Ohio Power Siting Board, Public Utilities Commission of Ohio, Pennsylvania Public Utility Commission, Tennessee Public Utility Commission, Virginia State Corporation Commission, and Public Service Commission of West Virginia. The Illinois Commerce Commission did not enter into this Agreement.

Importantly, PARSEC's Agreement represents a super-majority consensus among retail regulators and transmission siting authorities across the PJM region, representing states with diverse policies, regulatory structures, and load growth expectations. The Commission should therefore thoroughly consider this agreement and direct the TOs in the PJM region to implement it. PARSEC's Agreement is not only preferable because it tailors cost allocation to the distinct characteristics of long-term regional transmission planning, but it advances Order No. 1920's objectives of promoting state engagement and facilitating the efficient planning and development of long-term regional transmission.

PJM's proposed Long-Term Regional Transmission Planning ("LTRTP") process distinguishes Core LT Needs from Additional LT Needs. PJM develops a Core Plan and an All-in-One Plan that addresses both categories.[3] At PARSEC's request, PJM proposes a minimum benefit-cost ratio of 1.0 for the Core portfolio identified to address regional reliability and 1.25 for incremental Additional LT Need investments on a project-specific basis, recognizing that, in order to protect consumers against uncertainty in selecting and developing these LT facilities, there should be a minimum benefit-to-cost ratio for each type of project or portfolio of projects.[4]

The PARSEC has agreed to allocate costs for higher-voltage LTRT Facilities that solve Core LT Needs using a 75% solution-based DFAX ("SBDFAX") and 25% load-ratio-share ("LRS") methodology and for lower-voltage facilities using a 100% SBDFAX methodology.[5] For Long-Term Transmission Projects that address Additional LT Needs, whether in whole or in part, PARSEC's Agreement requires Relevant State Entities ("RSEs") to affirmatively accept the associated incremental costs through an opt-in mechanism. PJM may advance those identified projects or portions of projects into the final Long-Term Regional Transmission plan only if the participating states agree ("opt-in") and voluntarily fund them fully. This framework, along with other details discussed below, establishes the ex ante cost allocation methods for LTRT Facilities selected through PJM's Order No. 1920 long-term regional transmission planning process.

This ex ante framework is distinct from the proposed State Agreement Process ("SAP"), which FERC described as "a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) before or no later than six months after they are selected."[6] Both the SAP and the opt-in mechanism noted above are distinct from PJM's existing State Agreement Approach.[7]

[3] PJM Interconnection, L.L.C., Order Nos. 1920, 1920-A, and 1920-B Compliance Filing, Docket No. ER26-751-000, at 104-112 (Dec. 12, 2025) ("PJM Compliance Filing").
[4] *Id*. at 21.
[5] PARSEC proposes to retain the distinction between higher- and lower-voltage facilities in Schedule 12, with the dividing line being 500 kV and above or qualifying double-circuit 345 kV facilities. PJM Tariff, Schedule 12, §§ (b)(i)–(ii).
[6] Order No. 1920, Appendix B, *Pro Forma Open Access Transmission Tariff Attachment K*, § 2.3.
[7] PJM, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 6, § 1.5.9.

I. PARSEC'S AGREEMENT REFLECTS EXTENSIVE STATE ENGAGEMENT AND MUST BE CONSIDERED IN ESTABLISHING THE JUST AND REASONABLE REPLACEMENT RATE

The PARSEC began its work in August 2024. PARSEC approved its initial charter on September 19, 2024, and amended it on October 20, 2025, pursuant to votes of the OPSI Board of Directors.[8] The PARSEC adopted a set of principles to guide the development of this Agreement in early 2025.[9] Throughout 2025, PARSEC evaluated competing allocation methods with support from National Labs, internal polling, and eventually through internal mediated negotiations. The PARSEC reached an initial agreement in April 2026, albeit different from the agreement filed herein. Upon initial discussion with the TOs, it became clear that the PARSEC and the TOs did not agree on a cost allocation framework. Therefore, they jointly requested that FERC make available its Dispute Resolution Service should the parties agree to call upon it as part of their request for extension of the June 2026 compliance filing deadline.[10] The parties did utilize this service but were unable to reach agreement on all terms, and, therefore, the PARSEC submits its agreement accordingly.

Order No. 1920 allows RSEs to determine whether they have reached agreement.[11] In Order 1920-A, the Commission was persuaded that it should "consider any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process to which the Relevant State Entities agree."[12] FERC required that transmission providers provide "any and all supporting evidence and/or justification" concerning the states' agreement that RSEs request they include.[13] And FERC concluded that, "[t]he statute does not necessarily require the Commission to adopt the transmission provider's proposal on compliance, even if that proposal complies with the final rule's requirements."[14] Lastly, and critically, FERC stated that, "[t]his means that the Commission will consider the entire record – including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and the transmission provider's proposal – when setting the replacement rate."[15] The Commission should do just this, and recognize that the PARSEC's Agreement represents precisely what the 1920 Orders contemplated, allowed, and encouraged.

[8] PARSEC, PJM Area Relevant State Entities Committee Charter (enacted Sept. 19, 2024, amended Oct. 20, 2025) available at: https://opsi.us/wp-content/uploads/2025/10/2025.10.21_Relevant-State-Entities-Committee-Charter.pdf.
[9] PARSEC, Statement of Principles – Long-Term Regional Transmission Planning (Feb. 4, 2025) available at https://opsi.us/wp-content/uploads/2025/02/1920-Cost-Allocation-Principles.pdf.
[10] PARSEC and PJM Transmission Owners, *Unopposed Motion for Extension of Time and Request for Expedited Consideration*, Docket No. RM21-17-000 (June 4, 2026).
[11] Order No. 1920 at PP 1360–1361; Order No. 1920-A at PP 654, 681.
[12] Order No. 1920-A at P 654.
[13] *Id.* at P 655.
[14] *Id.* at P 658.
[15] *Id.* at P 659.

II. THE TRANSMISSION OWNERS INAPPROPRIATELY LEVERAGE EXISTING METHODOLOGIES IN THEIR AGREEMENT

The PJM TOs issued a notice on April 24, 2026, outlining their proposed approach to cost allocation under Order No. 1920.[16] The TO proposal would add section (b)(xix) to Schedule 12 of the PJM Tariff to allocate the costs of Regional Facilities and Necessary Lower Voltage Facilities selected through PJM's LTRTP process.[17] Under this approach, the TOs would allocate costs for facilities solely addressing Core LT Needs using the status quo cost allocation methodology for near-term transmission planning of 50% LRS and 50% SBDFAX, while facilities solely addressing Additional LT Needs would be cost-allocated using an 85% SBDFAX and 15% LRS methodology.[18] Other Lower Voltage Facilities would continue to use 100% SBDFAX.[19]

The TOs have since represented to PARSEC that they intend to file substantially the same proposal on November 19, 2026, with one modification applying the SAP to facilities addressing both Core and Additional LT Needs. Because PARSEC has not reviewed the TOs' final recommendation, PARSEC relies on the April 24, 2026, notice and the TOs' subsequent representations in describing their proposed cost allocation approach.

Under PJM's existing near-term reliability planning process, PJM allocates the costs of Regional Facilities and Necessary Lower Voltage Facilities using 50% LRS and 50% SBDFAX, while allocating the costs of other Lower Voltage Facilities using 100% SBDFAX.[20]

The TOs propose to carry forward this same methodology for Regional Facilities and Necessary Lower Voltage Facilities addressing Core LT Needs, while allocating Regional Facilities and Necessary Lower Voltage Facilities addressing Additional LT Needs using 85% SBDFAX and 15% LRS. As discussed below, PARSEC urges the Commission to reject the TOs' proposed allocations for high-voltage Facilities and projects addressing Additional LT Needs because the materially different assumptions and planning framework underlying PJM's LTRTP process warrant a distinct cost allocation methodology.

Allocating 50% of the costs of high-voltage facilities addressing Core LT Needs through LRS could assign substantial costs to customers in areas that are not experiencing rapid load growth or pursuing the public policies driving the need for these transmission facilities. It is therefore inappropriate to socialize such a large share of these costs through LRS. The regional benefit of LTRT Facilities, and the resulting costs socialized to ratepayers on an LRS basis, should more reasonably be set at 25%, not 50%. Likewise, involuntarily allocating any costs

[16] PJM Transmission Owners, *Notice of the PJM Transmission Owners Consultation with the Members Committee Regarding a Proposed Revision to the PJM Tariff*, Schedule 12, at 2–3 (Apr. 24, 2026) ("TOs' April Notice"), available here: https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260422/20260422-notice-of-pjm-tos-consultation-with-mc-regarding-a-proposed-revision-to-the-pjm-tariff-schedule-12---informational-posting-only.pdf.
[17] *Id.* at 1-2.
[18] *Id.* at 2-3.
[19] *Id.* at 2.
[20] PJM Tariff, Schedule 12, §§ (b)(i)–(iii).

associated with Additional LT Needs based on LRS is inappropriate because these facilities address needs beyond those required to maintain the long-term reliability of the PJM system.

III. PARSEC'S AGREEMENT IS TAILORED TO PJM'S LTRTP PROCESS

A. Core LT Costs Are Different from Costs Associated with Near-Term Reliability Projects

PARSEC proposes to allocate the costs of higher-voltage facilities addressing Core LT Needs using a 75% SBDFAX and 25% LRS methodology, while allocating the costs of lower-voltage facilities using a 100% SBDFAX methodology. PARSEC also proposes an opt-in methodology for allocating the costs of facilities solely addressing Additional LT Needs as well as the incremental portions of facilities addressing both Core and Additional LT Needs. Under this latter methodology, opt-in states bearing the costs must affirmatively agree to pay them, and PJM will advance the projects or portions of projects addressing Additional LT Needs only if they are fully funded. For SBDFAX allocations, PARSEC proposes a three-year rolling average once PJM has sufficient data, to minimize year-to-year volatility. The PARSEC framework is crucial to complying with the cost-causation principle.

The D.C. Circuit has described the cost-causation principle as "requir[ing] that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[21] The court evaluates "compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[22] Using a 50% LRS to allocate the costs associated with high-voltage Core LT Needs, as the TOs propose, does neither.

The cost-causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits.[23] The principle came from recognition that common costs of an integrated system must be allocated equitably among its beneficiaries.[24] The courts have held that this allocation does not require mathematical precision: "Allocation of costs is not a matter for the slide-rule."[25] But rates should correspond as closely as practicable to the costs of serving each customer class, while recognizing that "[c]ost itself is an inexact standard" that may support more than one reasonable rate.[26]

The Commission has repeatedly recognized that meaningful state participation in developing cost allocation methods can reduce siting delays, minimize costs, and promote the timely and efficient development of LTRT Facilities.[27] The Commission has further recognized

[21] *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (quoting *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).
[22] *Id.* at 1368–69 (citing K N Energy, 968 F.2d at 1300–01).
[23] Order No. 1920 at P 1305 & n.2786. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 85, 87 (D.C. Cir. 2014) (citing *Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007) ("NARUC")).
[24] *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 591 (1945); *Battle Creek Gas Co. v. FPC*, 281 F.2d 42, 45–46 (D.C. Cir. 1960).
[25] *Colorado Interstate*, 324 U.S. at 589; see also *Sithe/Indep. Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002).
[26] *Ala. Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982).
[27] Order No. 1920 at PP 124, 126, 1362; Order No. 1920-A at PP 659, 672–673.

that state-developed cost allocation methods take on heightened importance given the inherent uncertainty of long-term transmission planning.[28]

PARSEC's Agreement advances the Commission's objectives of having state buy-in so that LTRT Facilities can be efficiently approved and sited. PARSEC encourages the Commission to accept the agreement and direct its implementation. PARSEC's Agreement seeks to allocate costs more appropriately in accordance with the burdens imposed by entities and the benefits they receive. By contrast, the TOs continue to rely on a cost allocation methodology developed for a wholly different planning process, one involving far more certainty and fewer public policy inputs.

PJM's existing reliability planning process differs materially from its proposed LTRTP process. Its near-term analysis principally identifies actionable transmission to solve reliability needs expected to materialize five years in the future.[29] Although Schedule 6 provides for consideration of public policies through assumptions, sensitivities, and scenario analyses, the existing process does not incorporate those policies as comprehensively as the proposed 20-year LTRTP framework or as specifically required by Order No. 1920.[30]

PJM's five-year analysis primarily models existing generation and identified additions, including projects with signed interconnection agreements, and officially notified deactivations after their announced retirement dates.[31] While the 2026 RTEP also includes an eight-year capacity-expansion analysis, distinguishing a base scenario that excludes unannounced deactivations from a sensitivity incorporating policy-driven deactivations and offshore-wind targets, PJM describes the purpose of this analysis as identifying longer-term transmission needs and informing project selection and the sizing of nearer-term transmission upgrades, rather than independently developing transmission solutions to accommodate state public policies as is likely to occur under the LTRTP.[32]

PJM's statement on public policies within the 2026 RTEP further illustrates that distinction.[33] Apart from policies also captured as renewable portfolio standard ("RPS") targets, PJM did not specifically model states' other policies where it considered them too abstract to

[28] Order No. 1920 at P 1362; Order No. 1920-A at PP 631, 649, 659, 692.
[29] PJM Interconnection, L.L.C., Manual 14B: PJM Region Transmission Planning Process, § 2.1.2, at 32, Attachment B, § B.2, at 69.
[30] PJM, Review of 2026 RTEP Assumptions, slides 5, 9–10 (Apr. 7, 2026) ("2026 RTEP Assumptions") (identifying the five-year 2031 analysis and a separate eight-year 2034 analysis). PJM Operating Agreement, Schedule 6 §§ 1.5.1(a), 1.5.3(d), 1.5.6(b); PJM, Consideration of Federal and State Public Policy Initiatives Through PJM's Long-Term Regional Transmission Planning Process, at 4–5, available at https://www.pjm.com/-/media/DotCom/committees-groups/workshops/ltrtp/2023/20231215/20231215-informational-only---position-paper---consideration-of-federal-and-state-public-policy-initiatives-through-pjm-ltrtp-process.pdf; proposed Operating Agreement, Schedule 6-C § 1.5(a).
[31] 2026 RTEP Assumptions, slides 9–10, 12 (Apr. 7, 2026), available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260407/20260407-item-10---2026-rtep-assumption-update.pdf.
[32] *Id.* at slides 9–10, 18, 26.
[33] PJM, PJM Statement on Public Policies Submitted for Consideration in the 2026 RTEP, at 4, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260602/20260602-informational-only---pjm-statement-on-public-policies-within-the-2026-rtep.pdf.

model.[34] PJM recognized that these policies can nevertheless affect projects entering the interconnection queue, official deactivation notices, and its load forecast.[35]

In its proposed Order No. 1920 planning process, PJM explains that "although the designation of Core LT Needs focuses on what is necessary to address reliability, this approach to identify Core LT Needs is not exclusive of policy and does not 'discount' policy."[36] Core LT Needs are those needs that are associated with maintaining reliability based on a much broader set of inputs than near-term reliability planning, including "projected generation resource deactivations and additions; and a generation resource mix capable of meeting applicable reliability criteria."[37] PJM states that Core LT Needs "must be addressed to ensure reliability and other system needs" and that, "[w]hile primarily driven by maintaining system reliability, Core LT Needs will . . . also encompass economic and policy needs."[38] PJM's white paper further explains how generation resources will be included in identifying Core LT Needs, stating that PJM will "incorporate the most economic resources contributing to the capacity constraint until meeting the reliability criteria – including, for example, resources associated with RPS and their carve-outs."[39]

Additionally, PJM's proposed LTRTP process uses a 20-year planning horizon, which introduces considerable uncertainty about the actual users of a potential LT facility over the life of the project. This warrants an increase in the SBDFAX portion of the cost allocation to ensure that entities that benefit from a project based on power flows are assigned costs commensurate with their usage. Socializing 50% of the costs of these projects based on LRS is not just and reasonable. The modeling for LTRTP will use a distinct capacity-expansion approach. PJM will use a 20-year horizon and at least three plausible and diverse scenarios.[40] Its models incorporate public policies, economic assumptions, and projected resource additions and deactivations, including those driven by public policies, in order to meet defined reliability criteria.[41]

The two planning processes therefore model different assumptions and will result in very different transmission facilities based on different drivers. The Commission should evaluate these differences and not infer an allocation based on the shared "reliability" label. SBDFAX must be dominant in projects resulting from a 20-year forward projection. A 50% SBDFAX and 50% LRS allocation is not appropriate for Core LT Facilities.

B. States Must Voluntarily Accept Additional LT Costs

PARSEC has agreed to allocate the costs of projects, or portions of projects, addressing Additional LT Needs through a voluntary opt-in mechanism. PJM describes Additional LT Needs as those more influenced by drivers that differ from or extend beyond those necessary to

[34] *Id.*
[35] *Id.*
[36] PJM's Order 1920 Compliance Approach for Long-Term Regional Transmission Planning at 12 (Sept. 2025) ("PJM White Paper").
[37] PJM Compliance Filing at 69 & n.242 (proposed Operating Agreement, Schedule 6-C, § 1.6.2(a)).
[38] *Id.* at 69, 71.
[39] PJM White Paper at 12.
[40] PJM Compliance Filing at 7; proposed Operating Agreement, Schedule 6-C § 1.5(a).
[41] PJM Compliance Filing at 12, 69; proposed Operating Agreement, Schedule 6-C § 1.6.2(a).

maintain system reliability.[42] Additional LT Needs may arise from standalone economic needs, resource-specific policy requirements, or other policies that drive generation additions beyond those necessary to satisfy the one-in-ten reliability criterion.[43] These additional drivers may create reliability and economic transmission needs that PJM can address through LTRT Facilities, including facilities that simultaneously address Core LT Needs.[44] Requiring the implementation of an opt-in for these costs will promote the efficient selection and siting of these projects, recognizing that states will have already agreed to bear the costs of the projects they must assign to retail customers.

Under PARSEC's proposed opt-in process, PJM would provide PARSEC with project costs, estimated benefits, and SBDFAX distributions before the end of planning Year Three. For zones spanning multiple states, PJM would also estimate each state's share of the zonal SBDFAX allocation. Within six months after PJM releases the complete Core and All-in-One Plans, each state would decide whether to voluntarily assume the costs associated with each Additional LT Need project. PARSEC members would certify that they are authorized to communicate an opt-in decision and have the authority to bind their state.[45] PJM would then advance projects, or portions of projects, addressing Additional LT Needs into the Final Plan only if participating states commit to fully funding those costs, subject to final optimization.[46]

Only with full funding would a project be selected, meaning full funding would constitute a selection criterion for Additional LT Needs projects. This complies with Order No. 1920, which does not require PJM to select any project.[47]

PARSEC's opt-in is also the ex ante method for selected Additional LT Needs projects. Participating states would agree on how to allocate the full incremental costs *before* PJM selects the facility. This complies with Order No. 1920, which requires the applicable method to be known by selection.[48] FERC distinguished ex ante allocation from a State Agreement Process, which can replace the applicable method *after* selection.[49]

No state would be required to pay for Additional LT Need projects without its consent, and PJM could not shift unfunded costs to other states. This approach is consistent with the Commission's recognition that states may voluntarily fund additional benefits beyond those supported by baseline reliability and economic needs. The Commission specifically stated, "As an example, one potential cost allocation method that could be proposed to comply with Order No. 1920 would allocate costs commensurate with reliability and economic benefits region-wide,

[42] PJM Compliance Filing at 69, 71; PJM White Paper at 12-13.
[43] *Id.*
[44] *Id.*
[45] PARSEC Agreement, Appendix A, Opt-In Mechanism.
[46] *Id.* (PJM's December 2025 filing described a state opt-out mechanism that remained under development.) PJM Compliance Filing at 124–126.
[47] Order No. 1920 at P 1026; Order No. 1920-A at P 468.
[48] Order No. 1920 at P 1475; Order No. 1920-A at PP 789–790 ("We clarify that Dominion is correct that only the applicable cost allocation method must be determined by project selection.").
[49] Order No. 1920 at P 1475.

while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation."[50]

In contrast, the TOs propose a mandatory ex ante allocation for costs of projects, or portions of projects, that address Additional LT Needs. For Regional Facilities and Necessary Lower Voltage Facilities, the TOs propose to allocate costs using 85% SBDFAX and 15% LRS. Other Lower Voltage Facilities would be allocated using 100% SBDFAX.[51] While PARSEC considered various ex ante cost allocations for Additional LT Needs projects at length, PARSEC ultimately agreed to an opt-in approach as the only just and reasonable means to avoid states paying for Additional LT Need projects they do not believe they caused or from which they do not expect to benefit.

IV. PARSEC HAS AGREED UPON A UNANIMOUS STATE AGREEMENT PROCESS

In Appendix A, PARSEC describes the State Agreement Process through which RSEs may voluntarily agree to a cost allocation method to replace the ex ante cost allocation method for LTRT Facilities after PJM releases the final recommended Long-Term Regional Transmission Plan.

An affected Relevant State Entity ("Affected RSE") is an RSE whose state has load in a transmission zone allocated a positive share of the costs of an LTRT Facility, whether the facility addresses Core LT Needs, Additional LT Needs, or both. PJM could continue to allocate costs by transmission zone and collect the resulting charges from transmission customers serving load in those zones or could allocate costs pursuant to a State Agreement Method. PARSEC proposes that an SAP may be triggered before or after the PJM Board approves the Final Plan. The process may last longer than six months if it begins before project selection, but it must conclude, and any resulting cost allocation method must be filed, no later than six months after the Board selects the facilities, unless the Commission grants an extension.[52]

All PARSEC members may participate in an SAP. An Affected RSE may move for PARSEC to consider an alternative cost allocation methodology, and other Affected RSEs may propose alternatives for discussion. After they have had an opportunity to submit alternatives, PARSEC members will indicate which proposals they can support. Only a proposal receiving the unanimous agreement of Affected RSEs will proceed to the PJM Transmission Owners for filing.[53]

Before finalizing an agreement, Affected RSEs may request a reasonable number of additional analyses or data from PJM to help develop an alternative method. PJM will perform those analyses to the extent possible and provide the information necessary to support discussions, including its benefits quantification process, cost allocation formulas, and details on

[50] Order No. 1920-A at P 767.
[51] TOs' April Notice at 1–3; PJM Tariff, Schedule 12 §§ (b)(i)–(iii).
[52] PARSEC Agreement, Appendix A, PARSEC Recommended State Agreement Process, "Scope and Purpose" and "Initiation and Duration of the Process." Order No. 1920 at PP 1403–1404; Order No. 1920-A at P 708.
[53] *Id.* at "Governance and Membership" and "Proposing and Considering Cost Allocation Methodologies."

voluntary funding. If information delays warrant additional time, PARSEC may seek an extension from the Commission.[54]

An agreed-upon State Agreement Method, the outcome of the State Agreement Process, must identify the zones that will pay for the facilities or categories of facilities and, for a project-by-project allocation, the relevant cost share for each state or zone. It must also explain why the proposed method, rather than the Commission-approved ex ante method, is just and reasonable. The agreement is memorialized in writing and signed by the participating Affected RSEs, including written acknowledgment of any delegated voting authority. The PARSEC Chair will then communicate the agreement to the TO representative identified on PJM's Transmission Expansion Advisory Committee webpage.[55]

Per Order No. 1920-B, upon receipt of the signed State Agreement Method, the PJM TO representative is required to file the method with the Commission within 30 days, subject to the six-month deadline unless the Commission grants an extension, even if the TOs disagree with the method.[56] If the Commission approves the agreement, the State Agreement Method replaces the existing ex ante allocation for the project or group of projects at issue. The relevant TO then brings the project and resulting allocation before the relevant state regulatory authority for cost recovery.[57]

A State Agreement Method cannot allocate Additional LT Need costs to transmission customers serving load in a state without the state's affirmative consent. If the Affected RSEs do not reach unanimous agreement, the Commission-approved ex ante method continues to apply, including the Additional LT Need opt-in requirement. The Affected RSEs may terminate an SAP early by unanimous written consent.[58]

V. DOCUMENTS ENCLOSED

PARSEC submits the following:

- This transmittal letter; and
- Appendix A: PARSEC's Agreement on Long-Term Regional Transmission Cost Allocation Methods and a State Agreement Process.

[54] *Id.* at "Information Requests."
[55] *Id.* at "Requirements for the State Agreement Method" and "Communication of Agreement."
[56] Order No. 1920 at P 1291; Order No. 1920-A at PP 651, 654–655; Order No. 1920-B, 191 FERC ¶ 61,026, at PP 45, 47–48, 59 (2025).
[57] *PARSEC Agreement, Appendix A,* "PARSEC Proposal" and "Finalizing and Filing the Agreement."
[58] *Id.* at "Finalizing and Filing the Agreement," "Failure to Agree," and "Initiation and Duration of the Process."

VI. CORRESPONDENCE AND COMMUNICATIONS

Please direct correspondence and communications about this submission to:

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VII. CONCLUSION

PARSEC asks the Commission to adopt the Agreement in Appendix A as the just and reasonable replacement rate and direct PJM and the TOs to submit conforming filings within 60 days. Those filings must include a 75% SBDFAX and 25% LRS methodology for higher-voltage Core facilities and 100% SBDFAX for lower-voltage Core facilities. They must require affirmative opt-in for every project or portion of project that solves an Additional LT Need, and they must establish an SAP for both Core and Additional LT Need project categories with a mandatory filing obligation. These provisions and others in the agreement below appropriately align cost allocation with Order No. 1920 planning and advance the objectives of the Final Rule.

Respectfully submitted,

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On behalf of PARSEC

APPENDIX A

PJM AREA RELEVANT STATE ENTITIES COMMITTEE AGREEMENT ON LONG-TERM REGIONAL TRANSMISSION COST ALLOCATION METHODS AND A STATE AGREEMENT PROCESS[1]

Ex Ante Cost Allocation Method

- Core Method
    - 345 kV double circuit and above: 75% SBDFAX / 25% LRS
    - Lower-voltage facilities: 100% SBDFAX
    - Costs should be allocated zonally, as occurs pursuant to existing reliability methods

PJM will calculate the SBDFAX of Additional LT Needs projects or portions of projects that solve Additional LT Needs on a state-by-state basis by (1) estimating the percentage of each transmission zone within each PJM state and (2) using these estimates to convert the Zonal SBDFAX allocation to their state equivalents. This will help states understand the extent to which they would like to opt in to a project that solves Additional LT Needs.

Modifications to the status quo

- Apply a three-year rolling average to SBDFAX allocations to minimize year-to-year volatility, once PJM has enough data.
- PJM TOs should commit to consult with PJM Area Relevant State Entities Committee ("PARSEC") on modifications to this cost allocation framework should the TOs intend to file any changes after the first Order No. 1920 planning cycle.

Opt-In Mechanism

- Additional Method (incremental All-in-One Plan costs)
    - 345 kV double circuit and above: Opt-In
    - Lower voltage facilities: Opt-In
- The opt-in functions as a selection criterion, in that PJM can only select fully funded projects that solve Additional LT Needs.
    - However, the ultimate allocation methodology will be known prior to final project selection. Therefore, it will function as an ex ante method.
- Opt-in decisions must be made by PARSEC members. PARSEC members may delegate their ability to make an opt-in decision to another PARSEC member in their state pursuant

[1] PARSEC approved this Agreement pursuant to its Charter on November 13, 2026. The following PARSEC members agreed to this Agreement: the Delaware Public Service Commission, Delaware State Energy Office, Public Service Commission of the District of Columbia, Indiana Utility Regulatory Commission, Kentucky Public Service Commission, Kentucky State Board on Electric Generation and Transmission Siting, Maryland Public Service Commission, Michigan Public Service Commission, New Jersey Board of Public Utilities, New Jersey Department of Environmental Protection, North Carolina Utilities Commission, Ohio Power Siting Board, Public Utilities Commission of Ohio, Pennsylvania Public Utility Commission, Tennessee Public Utility Commission, Virginia State Corporation Commission, and Public Service Commission of West Virginia. The Illinois Commerce Commission did not enter into this Agreement.

to the PARSEC Charter. If there is more than one PARSEC member in a state, those members must provide a unanimous opt-in decision.

- PARSEC members must certify they are the entity authorized under FERC Order No. 1920 to communicate an opt-in decision and have the authority to bind the state.
- PJM should calculate and share information related to the costs, benefits, and SBDFAX distributions of projects in the All-in-One Plan before the conclusion of the third year of the Order No. 1920 planning process. States will communicate complete and final opt-in decisions no later than six months after PJM releases the complete Core and All-in-One Plans.
- For each project or portion of a project addressing Additional LT Needs, the affected PARSEC members must agree on how to allocate and fully fund its incremental costs before PJM makes its final selection. PJM will only advance projects addressing Additional LT Needs into the Final Plan if they are fully funded based on affirmative opt-in agreement of the affected PARSEC members. If states opt in to the full costs of a project that solely solves Additional LT Needs or the portion of a project that solves Additional LT Needs, PJM should proceed to include that project in the Final Plan. PJM will advance projects that are fully funded into the Final Plan, subject to final optimization with other remaining projects.
- If a project is partially unfunded based on affirmative opt-in commitments made before the conclusion of the relevant planning cycle – either initially or during a future year – PJM will not advance the project into the Final Plan.

PARSEC Recommended State Agreement Process

A State Agreement Process ("SAP") is "a process by which Relevant State Entities may voluntarily agree to a cost allocation method to replace the ex ante cost allocation method for LTRT Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation."[2]

Order No. 1920 "decline[s] to define what constitutes agreement among Relevant State Entities, how such agreement is reached, and which Relevant State Entities must reach such agreement during the Engagement Period. Instead, [it] leave[s] such matters . . . to the Relevant State Entities participating in the Engagement Period to determine."[3] In Order No. 1920-B, the Commission affirmed its authority under FPA Section 206 to require transmission providers to include RSEs' agreed-upon Long-Term Regional Transmission Cost Allocation Method(s) and/or SAP resulting from the Engagement Period in the transmission providers' transmittal or as an attachment to their Order No. 1920 regional transmission planning and cost allocation compliance filing.[4]

Under Order No. 1920, PJM RSEs are empowered to develop an SAP enabling the development of their own State Agreement Method to pay for projects that are evaluated and approved through PJM's LTRTP study process. The PJM TOs do not have to agree with an SAP developed during the Engagement Period. However, if RSEs request it, the PJM

[2] Order No. 1920 at P 1296.
[3] *Id.* at P 1360.
[4] Order No. 1920 at P 1291; Order No. 1920-A at PP 651, 654–655; Order No. 1920-B, 191 FERC ¶ 61,026, at PP 45, 47–48, 59 (2025).

Transmission Owners ("TOs") are obligated to include the SAP in their Order No. 1920 compliance filing.

PARSEC Proposal

In accordance with Order No. 1920, PARSEC proposes the following SAP for the PJM region and requests the PJM TOs include it in their Order No. 1920 compliance filing. PARSEC also requests that the PJM TOs' Order No. 1920 compliance filing include a commitment to file any method or approach agreed to by PARSEC, even if the PJM TOs do not agree with the method or approach, recognizing that transmission developers must be able to recover their costs.

Scope and Purpose

The purpose of this SAP is to establish a clear, structured, and voluntary mechanism for members of the PARSEC to agree upon a cost allocation methodology or methodologies (State Agreement Method(s)) for long-term regional transmission facilities identified and evaluated under FERC Order No. 1920. The SAP applies to facilities addressing Core LT Needs, Additional LT Needs, or both.

Governance and Membership

PARSEC is the Relevant State Entity Committee for the PJM region constituted pursuant to FERC Order No. 1920. An Affected RSE is a Relevant State Entity whose state has load in a transmission zone allocated a positive share of the costs of an LTRT Facility, whether the facility addresses Core LT Needs, Additional LT Needs, or both. The membership and allocation of votes described in the PARSEC Charter shall control the membership and voting structure of any SAP PARSEC initiates, as long as this framework does not specify the relevant vote with more detail. Non-PARSEC members are able to participate in SAP meetings pursuant to the PARSEC Charter as it may be amended from time to time. Before each SAP starts, Affected RSEs may agree to designate additional entities to participate and/or establish opportunities for public input.

All PARSEC members may participate in an SAP. Votes to modify the ex ante method must be unanimous among those entities that are actually allocated costs for the project or class of projects for which PARSEC is considering submitting an alternate cost allocation method. Each PJM state with an Affected RSE, including the District of Columbia, is entitled to one vote on any State Agreement Method developed as part of the SAP. If there is more than one Affected RSE in a single PJM state or Washington, D.C., then the Affected RSEs must split their votes in accordance with the PARSEC Charter. Decisions of the SAP may only be reached by the unanimous agreement of the affected parties. This threshold can be modified by the unanimous agreement of all PARSEC members.

Initiation and Duration of the Process

The SAP may be triggered before or after the PJM Board approves the Final Plan. The process may last longer than six months if it commences prior to project selection, but it must conclude, and any resulting method must be filed, no later than six months after the PJM Board formally selects LTRT Facilities for inclusion in the Regional Transmission Expansion Plan, unless the Commission grants an extension. The Affected RSEs will strive to provide a State Agreement Method to the PJM TOs with enough advance notice so they can prepare any necessary

FERC filing. An SAP may be terminated early upon the unanimous written consent of the Affected RSEs.

Proposing and Considering Cost Allocation Methodologies

Alternative cost allocation methodologies can be considered upon a motion by an individual Affected RSE or multiple Affected RSEs. Other Affected RSEs may provide alternative proposals for discussion and consideration. After Affected RSEs have had the opportunity to provide an alternative methodology, all Affected RSEs will be asked to indicate which proposals they could support. Only proposals receiving unanimous support of the affected parties will be forwarded to the PJM TOs for filing.

Requirements for the State Agreement Method

Any agreed-upon State Agreement Method must identify:

- Which state and zone will pay for specific facilities or categories of facilities,
- The relevant cost share for each state and/or zone, if on a project-by-project basis, and
- A statement as to why the proposed methodology that should be applied in lieu of the ex ante method approved by the Commission is just and reasonable.

Communication of Agreement

Once reached, the final, agreed-upon cost allocation method will be memorialized in writing and signed by all participating affected PARSEC members, including a written acknowledgment from PARSEC members who have delegated their voting authority to another entity within their state. The PARSEC Chair will communicate any agreement(s) of affected PARSEC members to a representative of the Transmission Owners as detailed on the PJM Transmission Expansion Advisory Committee webpage.

Information Requests

After the initiation of an SAP, Affected RSEs may formally request a reasonable number of additional analyses or data from PJM that could facilitate the design of an agreed-upon alternative cost allocation methodology, which PJM must provide to the extent possible.

To support discussions, PJM shall provide all necessary information, including the benefits quantification process, cost allocation formulas, and details on the voluntary funding process. Should there be delays in receiving information from the Transmission Provider, PARSEC may seek extension of the SAP beyond six months following selection pursuant to FERC Order No. 1920.

Finalizing and Filing the Agreement

Upon receipt of the signed State Agreement Method, the PJM TO representative shall coordinate the filing of the alternative method within 30 days, subject to the six-month filing deadline unless extended by the Commission. PARSEC will strive to provide the method to the PJM TOs with enough time to receive and consider feedback before providing the to-be-filed version of the State Agreement Method. If approved by FERC, the State Agreement Method overrides the existing ex ante cost allocation method for the particular project or group of projects

at issue. A State Agreement Method cannot allocate Additional LT Need costs to transmission customers serving load in a state without that state's affirmative opt-in.

The relevant TO will bring the project and the resulting cost allocation agreement before the relevant state regulatory authority for cost recovery.

Failure to Agree

If Affected RSEs do not reach a unanimous decision, the project or projects at issue will be allocated according to the ex ante method approved by the Commission, including the Additional LT Needs opt-in requirement.

Amendments and Termination

Any amendments to this State Agreement Process framework require the unanimous consent of all PARSEC members. Termination of a State Agreement Process will occur not later than six months after project selection, as may be modified by an order of the Commission, or by unanimous consent of the affected parties prior to six months after project selection.