April 22, 2024

Notice of PJM Transmission Owners Consultation with the Members Committee Regarding Proposed Changes to the PJM Tariff Associated with Transfer of Operating Agreement Schedule 6 to the PJM Tariff

On April 17, 2024, the PJM Board of Managers ("PJM Board") invoked Operating Agreement ("OA"), section 7.7(v) stating its intent to submit to the Members Committee proposed amendments to the OA. The Board stated that the proposed OA revisions would serve to move Schedule 6 (including Schedules 6-A and 6-B) of the OA to the PJM Tariff along with any necessary conforming OA and Tariff changes, with the understanding that revisions to the Consolidated Transmission Owners Agreement ("CTOA") that have been under consideration by the Transmission Owners Agreement Administrative Committee ("TOA-AC") since February 6, 2024, will be needed to effectuate a potential affirmative vote of the Members to move Schedule 6 (including Schedules 6-A and 6-B). The PJM Board requested that the Members vote on the proposed OA amendments in a timely manner, as the PJM Board expects to gather comments and discuss this matter at its next Board meeting, scheduled to occur immediately after the PJM Annual Meeting.

In addition to the revisions to the CTOA, the PJM Board's invocation of OA, section 7.7(v) necessarily requires changes to the PJM Tariff to reflect the proposed new location of the Regional Transmission Expansion Planning Protocol ("Planning Protocol") at Tariff, Schedule 19, and to replace references to Operating Agreement, Schedule 6 with the new Tariff schedule. On April 22, 2024, PJM issued a notice to the Members Committee pursuant to Tariff, Section 9.2(b) and CTOA section 7.5.1(ii), which included all proposed conforming changes to the Tariff and OA to effectuate the move of the Planning Protocol from the OA to the Tariff ("April 22 Notice").

Under Section 7.3.2 of the CTOA and Tariff, Section 9.1(b), changes to Tariff, Schedules 12, 12-Appendix A, 12-Appendix B, 12 - Appendix C, and 12-B and Attachments M-3 and M-4 fall within the Transmission Owners' Section 205 filing rights and must be approved by the TOA-AC. Accordingly, the TOA-AC through this notice, and consistent with the PJM Board's April 17, 2024 invocation, is initiating consultation pursuant to Tariff Section 9.1(b) and CTOA Section 7.3.2 with the Members Committee regarding the proposed changes to Tariff, Schedules 12, 12-Appendix A, 12-Appendix B, 12 - Appendix C, and 12-B and Attachments M-3 and M-4. As is the case with respect to other affected Tariff provisions, the references to Operating Agreement, Schedule 6 sections contained in these schedules must be changed to Tariff, Schedule 19 for these schedules to operate properly once the Planning Protocol has been moved to the Tariff.

The redlined and clean changes to Tariff, Schedules 12, 12-Appendix A, 12-Appendix B, 12 - Appendix C, and 12-B and Attachments M-3 and M-4 are attached to this notice as Attachments A and B, respectively. These proposed changes to the Tariff will be considered at a meeting of the TOA-AC scheduled for May 23, 2024. If the CTOA Amendments currently under consideration by the TOA-AC and the proposed revisions to Tariff, Schedules 12, 12-Appendix A, 12-Appendix B, 12-Appendix C, and 12-B and Attachments M-3 and M-4 are both approved in accordance with Section 8.5.1 of the CTOA, the TOA-AC intends to authorize a filing under Section 205 of the Federal Power Act with the Federal Energy Regulatory Commission proposing these revisions to the PJM Tariff along with other changes to the Tariff proposed by PJM.

Written comments on the proposed changes to Tariff Schedules 12, 12- Appendix A, 12 - Appendix B, 12 - Appendix C, and 12-B and Attachments M-3 and M-4 may be submitted for consideration by email to: (Comments_for_Transmission_Owners@pjm.com) on or before May 21, 2024.

Attachment A

Revisions to the
PJM Open Access Transmission
Tariff

(Marked / Redline Format)

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~~ Tariff, Schedule 19 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~~Tariff, Schedule 19, 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~~ Tariff, Schedule 19, 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.

(6) Except as provided in this subsection, no cost responsibility shall be assigned to a Responsible Zone unless the magnitude of the distribution factor is greater than or equal to 0.01, and any distribution factor of a smaller magnitude shall be set equal to zero. This rule shall not apply to the Zone(s) in which the Required Transmission Enhancement is located, which shall be assigned cost responsibility based on its distribution factor, regardless of the magnitude.

(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~~Tariff, Schedule 19, 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~~Tariff, Schedule 19, 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~~Tariff, Schedule 19, 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~~Tariff, Schedule 19, 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) and (b)(v) 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~~Tariff, Schedule 19, 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~~Tariff, Schedule 19, 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~~Tariff, Schedule 19, 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~~Tariff, Schedule 19, 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~~Tariff, Schedule 19, 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~~Tariff, Schedule 19, section 1.5.8(n), were not included in an ~~Operating Agreement, Schedule 6~~Tariff, Schedule 19, 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.

(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.

SCHEDULE 12 – APPENDIX A

Required Transmission Enhancements Approved By The PJM Board On Or After February 1, 2013, Responsible Customers And Associated Transmission Owner Revenue Requirements.

This Schedule 12 – Appendix A applies only to the assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider on or after February 1, 2013, or (2) applicable to Required Transmission Enhancements approved by the PJM Board ~~pursuant to Section 1.6 of the PJM Operating Agreement~~ on or after such effective date.

Required Transmission Enhancements that have been placed in service in PJM, the Transmission Owner(s) responsible for constructing and owning and/or financing such Required Transmission Enhancements, the Responsible Customers and the annual revenue requirement upon which Transmission Enhancement Charges determined in accordance with section (c) of Schedule 12 are based, are set forth below. Unless otherwise stated, all designations of Responsible Customers refer collectively to all Firm Point-to-Point Transmission Service and Network Integration Transmission Service customers in each indicated Zone and state the proportional (percentage) cost responsibility allocated to the indicated customers in each Zone. Zones are identified using the short names stated in Attachment J to the Tariff.

SCHEDULE 12 – APPENDIX B

Joint Planning Or Coordination Agreements Between PJM And Other Regions Or Transmission Planning Authorities

1. Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., which can be found at miso-joa.pdf (pjm.com);

2. Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. and The Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol, which can be found at https://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx;~~.~~

3. Interregional transmission coordination between Southeastern Regional Transmission Planning region participants and PJM pursuant to ~~Schedule 6-A of the Operating Agreement and~~ Tariff, Schedule 12-B and Schedule 19-A ~~of the Tariff~~ and the corresponding provisions of the tariffs of the jurisdictional Southeastern Regional Transmission Planning region participants;~~.~~

4. Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., which is found at nyiso-joa.ashx (pjm.com);

5. Joint Reliability Coordination Agreement among and between Tennessee Valley Authority, Louisville Gas and Electric Co. and Kentucky Utilities Co., and PJM Interconnection, L.L.C., which can be found at joint-reliability-agreement-jrca-pjm-tva.ashx;

6. Adjacent Reliability Coordinator Coordination Agreement between PJM Interconnection, L.L.C. VACAR South RC, those being Duke Energy Progress, Inc., Duke Energy Carolinas, LLC, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas, LLC, which can be found at https://www.pjm.com/-/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx; and

7. Amended and Restated Agreement Joint Operating Agreement Among and Between PJM Interconnection L.L.C., and Duke Energy Progress, L.L.C, which is found at progress-joa.pdf (pjm.com).

Schedule 12 - Appendix C

State Agreement Public Policy Projects Constructed Pursuant to the State Agreement Approach

This Schedule 12 - Appendix C applies only to the assignment of cost responsibility of State Agreement Public Policy Projects constructed in accordance with ~~Operating Agreement, Schedule 6~~Tariff, Schedule 19, section 1.5.9 among Responsible Customers.

(1) Rate Schedule FERC No. 49, State Agreement Approach Agreement By and Among PJM Interconnection, L.L.C. and New Jersey Board of Public Utilities

In accordance with the FERC order in Docket Nos. ER22-2690-000 and -001, 181 FERC ¶ 61,178 (2022), cost responsibility for the State Agreement Public Policy Projects shall be assigned annually on a load-ratio share basis among Network Customers in the State of New Jersey determined in accordance with Schedule 12, section (c)(4), and customers using Point-to-Point Transmission Service with a Point of Delivery within the State of New Jersey determined in accordance with Schedule 12, section (c)(5), as follows:

With respect to each Zone located in the State of New Jersey, 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.

Identifier	Description	Responsible Customers (percentage share)
b3737.1	Reconfigure Larrabee 230 kV substation	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.2	Larrabee substation – 230 kV equipment for direct connection	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.3	Lakewood Generator substation – Update relay settings on the Larrabee 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.4	B54 Larrabee – South Lockwood 34.5 kV line transfer	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.5	Larrabee Collector station – Larrabee 230 kV new line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.6	Larrabee Collector station – Smithburg No.1 500 kV line (new asset). New 500 kV line will be built double circuit to accommodate a 500 kV line and a 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.7	Rebuild G1021 Atlantic – Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500 kV/230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.8	Smithburg substation 500 kV expansion to 4-breaker ring	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.9	Larrabee substation upgrades	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.10	Atlantic 230 kV substation – Convert to double-breaker double-bus	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.11	Freneau substation – Update relay settings on the Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.12	Smithburg substation – Update relay settings on the Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.13	Oceanview substation – Update relay settings on the Atlantic 230 kV lines	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.14	Red Bank substation – Update relay settings on the Atlantic 230 kV lines	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.15	South River substation – Update relay settings on the Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.16	Larrabee substation – Update relay settings on the Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.17	Atlantic substation – Construct a new 230 kV line terminal position to accept the generator lead line from the offshore wind Larrabee Collector station	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.18	G1021 (Atlantic – Smithburg) 230 kV upgrade	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.19	R1032 (Atlantic – Larrabee) 230 kV upgrade	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.20	New Larrabee Collector station – Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.21	Larrabee – Oceanview 230 kV line upgrade	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.22	Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 bay breaker and a half substation with a nominal current rating of 4000 A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.23	Rebuild the underground portion of Richmond – Waneeta 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.24	Upgrade Cardiff – Lewis 138 kV by replacing 1590 kcmil strand bus inside Lewis substation	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.25	Upgrade Lewis No. 2 – Lewis No. 1 138 kV by replacing its bus tie with 2000 A circuit breaker	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.26	Upgrade Cardiff – New Freedom 230 kV by modifying existing relay setting to increase relay limit	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.27	Rebuild approximately 0.8 miles of the D1018 (Clarksville –Lawrence 230 kV) line between Lawrence substation (PSEG) and structure No. 63	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.28	Reconductor Kilmer I – Lake Nelson I 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.29	Convert the six-wired East Windsor – Smithburg E2005 230 kV line (9.0 miles) to two circuits: One a 500 kV line and the other a 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.30	Add third Smithburg 500/230 kV transformer	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.31	Additional reconductoring required for Lake Nelson I –Middlesex 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.32	Rebuild Larrabee – Smithburg No. 1 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.33	Reconductor Red Oak A – Raritan River 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.34	Reconductor Red Oak B – Raritan River 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.35	Reconductor small section of Raritan River – Kilmer I 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.36	Replace substation conductor at Kilmer and reconductor Raritan River – Kilmer W 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.37	Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run – Hope Creek 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.38	Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV switching station, and relocate the Linden – Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV station	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.39	Bergen subproject: Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.40	Windsor to Clarksville subproject: Create a paired conductor path between Clarksville 230 kV and JCPL Windsor Switch 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.41	Windsor to Clarksville subproject: Upgrade all terminal equipment at Windsor 230 kV and Clarksville 230 kV as necessary to create a paired conductor path between Clarksville and JCPL East Windsor Switch 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.42	Upgrade inside plant equipment at Lake Nelson I 230 kV station	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.43	Upgrade Kilmer W – Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.44	Upgrade Lake Nelson – Middlesex – Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.45	Reconductor 0.33 miles of PPL's portion of the Gilbert –Springfield 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.46	Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.47[+]	Build a new North Delta 500 kV substation with four bay breaker and half configuration. The substation will include 12 500 kV breakers and one 500/230 kV transformers, will allow the termination of six 500 kV lines	**Reliability Driver (26.73%):** **Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / Dominion (13.32%) / DPL (2.60%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** PECO (100%) **Public Policy Driver (73.27%):** AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.48	Build a new North Delta – Graceton 230 kV line by rebuilding 6.07 miles of the existing Cooper – Graceton 230 kV line to double circuit	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.49	Bring the Cooper – Graceton 230 kV line "in and out" of North Delta by constructing a new double-circuit North Delta – Graceton 230 kV (0.3 miles) and a new North Delta – Cooper 230 kV (0.4 miles) cut-in lines	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

[+] b3737.47 is an Incremental Multi-Driver Project that includes both a reliability driver and a public policy driver. Accordingly, b3737.47 is included on both Tariff, Schedule 12–Appendix A, section 28 and Tariff, Schedule 12–Appendix C, section 1.

Identifier	Description	Responsible Customers (percentage share)
b3737.50	Bring the Peach Bottom – Delta Power Plant 500 kV line “in and out” of North Delta by constructing a new Peach Bottom – North Delta 500 kV (0.3 miles) cut-in and cut-out lines	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.51	Replace four 63 kA circuit breakers "205," "235," "225" and "255" at Peach Bottom 500 kV with 80 kA	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.52	Replace one 63 kA circuit breaker "B4" at Conastone 230 kV with 80 kA	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.53	Remove the existing E83 115 kV line (not in-service) to accommodate the new 500 kV/230 kV lines (approximately 7.7 miles)	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.54	Remove the existing H2008 Larrabee – Smithburg No. 2 230 kV line to accommodate the new 500 kV/230 kV lines	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.55	Middlesex substation 230 kV – Replace the 2000A circuit switcher at Middlesex switch point for the Lake Nelson I1023 230 kV exit	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.56	Build a new North Delta – Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper – Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO and BGE. This subproject is for BGE's portion of the line rebuild, which is 2.16 miles	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.59	Windsor to Clarksville subproject: Upgrade terminal equipment at Windsor 230 kV station	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.60	Perform a Pre-build Infrastructure evaluation study in alignment with the NJBPU Solicitation Guidance Document requirements	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)

SCHEDULE 12-B

Allocation of Costs of Certain Interregional Transmission Projects Located in the PJM and SERTP Regions

1. **Cost Allocation:** The PJM Region portion determined under Section 3 of this Schedule 12-B of the cost of an interregional transmission project located in the PJM Region and the Southeastern Regional Transmission Planning Process ("SERTP") region shall be allocated in accordance with Schedule 12 of the Tariff, provided that the interregional transmission project satisfies all of the criteria in Section 2 of this Schedule 12-B.

2. **Proposal of Interregional Transmission Projects for Interregional Cost Allocation Purposes:** For an interregional transmission project to be eligible for interregional cost allocation purposes within the SERTP region and the PJM Region, all of the following criteria must be met:

A. The interregional transmission project must be interregional in nature, which requires that it must:

- Be physically located in both the SERTP region and the PJM Region;
- Interconnect to transmission facilities in both the PJM and SERTP regions. The facilities to which the project is proposed to interconnect may be either existing transmission facilities or transmission projects included in the regional transmission expansion plan that are currently under development; and
- Meet the threshold criteria for transmission projects potentially eligible to be included in the regional transmission plans for purposes of cost allocation in both the SERTP region and the PJM Region, pursuant to the regional transmission planning process of the SERTP region and the Regional Transmission Expansion Plan prepared by the Office of the Interconnection pursuant to ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19, respectively.

B. The interregional transmission project must be proposed for purposes of cost allocation in both the SERTP region and the PJM Region:

- The transmission developer and project submittal must satisfy all criteria specified in the respective regional transmission processes; and
- The proposal should be submitted in the timeframes outlined in the respective regional transmission planning processes.

C. The interregional transmission project must be selected both in the regional transmission plan of the SERTP region and in the Regional Transmission Expansion Plan prepared by the Office of the Interconnection for the PJM Region:

- The costs of the interregional transmission project eligible for interregional cost allocation shall only be allocated to a region if that region has selected the interregional transmission project in its regional transmission plan for purposes of cost allocation; and

- No cost shall be allocated to a region that has not selected the interregional transmission project in its regional transmission plan for purposes of cost allocation.

3. **Allocation of Costs for Interregional Transmission Projects Between the SERTP and PJM Regions:** The cost of an interregional transmission project selected for purposes of cost allocation in the regional transmission plans of both the SERTP region and PJM Region shall be allocated for interregional cost allocation purposes to those regions as provided below:

A. The share of the costs of an interregional transmission project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region's displaced regional transmission project(s) to the total of the present values of the estimated costs of the displaced regional transmission projects in all regions that have selected the interregional transmission project in their regional transmission plans for purposes of cost allocation. The present values used in the cost allocation shall be based on a common date, comparable cost components, and the latest cost estimates used in the determination to include the interregional transmission project in the respective regional plans for purposes of cost allocation. The applicable discount rate(s) used for the SERTP region for interregional cost allocation purposes will be based upon the after-tax weighted average cost of capital of the SERTP transmission owners whose projects would be displaced by the proposed interregional transmission project. The applicable discount rate for the PJM Region shall be the discount rate included in the assumptions that are reviewed with the PJM Board of Managers each year for use in the economic planning process.

B. When all or a portion of an interregional transmission project is to be located within a region in which there is no displaced regional transmission project, such region may, at its sole discretion, select the interregional transmission project for inclusion in its regional transmission plan; provided, however, that no portion of the costs of the interregional transmission project shall be allocated to such region pursuant to Section 3(A).

C. Nothing in this Schedule 12-B shall govern the further allocation of costs allocated to a region pursuant to this Section 3 within such region. For purposes of clarification, the further allocation of costs allocated by this Section 3 within the PJM Region shall be governed by the applicable provisions of Schedule 12 of the Tariff.

D. The following example illustrates the cost allocation provisions in Section 3:

- Regions A and B, through the joint evaluation process prescribed in ~~Schedule 6-A of the Operating Agreement~~Tariff, Schedule 19-A have included Transmission Project Z in their respective regional plans for purposes of cost allocation. Transmission Project Z was determined to address both regions' needs more efficiently or cost effectively than Transmission Project X in Region A and Transmission Project Y in Region B.
- The estimated cost of Transmission Projects X and Y are Cost (X) and Cost (Y) respectively. As described in Section 3(A), these costs shall be based upon common cost components.

- The number of years from the common present value date to the year associated with the cost estimates of Transmission Projects X and Y are N(X) and N(Y) respectively.
- Recognizing that the regions may have different discount rates, for purposes of this example D_A is the discount rate used for Transmission Project X and D_B is the discount rate used for Transmission Project Y.
- Based on the foregoing assumptions and the allocation of costs based upon displaced regional transmission projects as prescribed in Section 3(A), the following illustrative formulas would be used:
  - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+ D_A)^{N(X)}$
  - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+ D_B)^{N(Y)}$
  - Cost Allocation to Region A = PV Cost (X) / [PV Cost (X) + PV Cost (Y)]
  - Cost Allocation to Region B = PV Cost (Y) / [PV Cost (X) + PV Cost (Y)]
- Applying the above formulas, if:
  - Cost (X) = $60 Million and N(X) = 8.25 years
  - Cost (Y) = $40 Million and N(Y) = 4.50 years
  - D_A = 7.5% per year
  - D_B = 7.4% per year

- Then:
  - PV Cost (X) = $60/(1+0.075)^{8.25}$ = 33.0 Million
  - PV Cost (Y) = $40/(1+0.074)^{4.50}$ = 29.0 Million
  - Cost Allocation to Region A = 33.0 / (33.0 + 29.0) = 53.2% of the cost of Transmission Project Z
  - Cost Allocation to Region B = 29.0 / (33.0 + 29.0) = 46.8% of the cost of Transmission Project Z

4. **Merchant Transmission and Transmission Owner Projects:** Nothing in this Schedule 12-B shall preclude the development of interregional transmission projects that are funded by merchant transmission developers or by individual transmission owners.

5. **Exclusivity with Respect to Interregional Transmission Projects Selected for Interregional Cost Allocation Purposes:** The following provisions shall apply regarding other cost allocation arrangements:

A. Except as provided in Section 5(B), the provisions in this Schedule 12-B are the exclusive means by which any costs of an interregional transmission project selected for interregional cost allocation purposes between the SERTP region and the PJM Region may be allocated between or among those regions.

B. A transmission owner(s) or transmission developer(s) may propose to fund or allocate, on a voluntary basis, the cost of an interregional transmission project selected for interregional cost allocation purposes using an allocation other than the allocation that results from the methodology set forth in Section 3, provided that, should the allocation of cost of such interregional transmission project be subject to the Commission's jurisdiction, such allocation proposal is accepted for filing by the Commission in accordance with the filing rights with respect to cost allocation set forth in Section 6 of this Schedule 12-B and provided further that no allocation shall be made to any region that has not agreed to that allocation.

6. **Section 205 Filing Rights with Respect to Interregional Transmission Projects Selected for Interregional Cost Allocation Purposes:** Solely with respect to interregional transmission projects evaluated under ~~Schedule 6-A of the Operating Agreement~~Tariff, Schedule 19-A and selected by the SERTP and PJM regional transmission planning processes for purposes of interregional cost allocation purposes, the following provisions shall apply:

A. Except as provided in Sections 5 and 6(B) of this Schedule 12-B, nothing in this Schedule 12-B will convey, expand, limit or otherwise alter any rights of the transmission owners, transmission developers or other market participants to submit filings under Section 205 of the Federal Power Act ("FPA") regarding cost allocation or any other matter.

B. The cost allocation provisions in this Schedule 12-B shall not be modified under Section 205 of the FPA without the mutual consent of the holders of the FPA Section 205 rights with respect to interregional cost allocation in the SERTP region and the PJM Region.

7. **Consequences to Other Regions from Interregional Transmission Projects:** Except as provided in this Schedule 12-B, or in other documents, agreements or tariffs on file with the Commission, neither the PJM Region nor the transmission providers in the SERTP region shall be responsible for compensating another planning region for required upgrades or for any other consequences in another planning region associated with interregional transmission projects identified pursuant to ~~Schedule 6-A of the Operating Agreement~~Tariff, Schedule 19-A.

ATTACHMENT
M-3
ADDITIONAL PROCEDURES FOR PLANNING
SUPPLEMENTAL PROJECTS AND ASSET MANAGEMENT PROJECTS

(a) Applicability. Each Transmission Owner shall be responsible for planning and constructing in accordance with ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19 as provided in this Attachment M-3, to the extent applicable, (i) Asset Management Projects, as defined herein, (ii) Supplemental Projects, as defined in ~~section 1.42A.02 of the Operating Agreement~~the Tariff, and (iii) any other transmission expansion or enhancement of Transmission Facilities that is not planned by PJM to address one or more of the following planning criteria:

1. NERC Reliability Standards (which includes Applicable Regional Entity reliability standards);

2. Individual Transmission Owner planning criteria as filed in FERC Form No. 715 and posted on the PJM website, provided that the Additional Procedures for the Identification and Planning of EOL Needs, set forth in section (d), shall apply, as applicable;

3. Criteria to address economic constraints in accordance with section 1.5.7 of ~~the Operating Agreement~~Tariff, Schedule 19 or an agreement listed in Schedule 12-Appendix B;

4. State Agreement Approach expansions or enhancements in accordance with section 1.5.9(a)(ii) of ~~the Operating Agreement~~Tariff, Schedule 19; or

5. An expansion or enhancement to be addressed by the RTEP Planning Process pursuant to section (d)(2) of this Attachment M-3 in accordance with RTEP Planning Process procedures in ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19.

This Attachment M-3 shall not apply to CIP-014 mitigation projects that are subject to Attachment M-4.

(b) Definitions.

1. Asset Management Project. "Asset Management Project" shall mean any modification or replacement of a Transmission Owner's Transmission Facilities that results in no more than an Incidental Increase in transmission capacity undertaken to perform maintenance, repair, and replacement work, to address an EOL Need, or to effect infrastructure security, system reliability, and automation projects the Transmission Owner undertakes to maintain its existing electric transmission system and meet regulatory compliance requirements.

2. Attachment M-3 Project. "Attachment M-3 Project" means (i) an Asset Management Project that affects the connectivity of Transmission Facilities that

are included in the Transmission System, affects Transmission Facility ratings or significantly changes the impedance of Transmission Facilities; (ii) a Supplemental Project; or (iii) any other expansion or enhancement of Transmission Facilities that is not excluded from this Attachment M-3 under any of clauses (1) through (5) of section (a). "Attachment M-3 Project" does not include a project to address Form No. 715 EOL Planning Criteria.

3. Incidental Increase. "Incidental Increase" shall mean an increase in transmission capacity achieved by advancements in technology and/or replacements consistent with current Transmission Owner design standards, industry standards, codes, laws or regulations, which is not reasonably severable from an Asset Management Project. A transmission project that results in more than an Incidental Increase in transmission capacity is an expansion or enhancement of Transmission Facilities.

4. Transmission Facilities. "Transmission Facilities" shall have the meaning set forth in the Consolidated Transmission Owners Agreement~~, section 1.27~~.

5. EOL Need. "EOL Need" shall mean a need to replace a transmission line between breakers operating at or above 100 kV or a transformer, the high side of which operates at or above 100 kV and the low side of which is not connected to distribution facilities, which the Transmission Owner has determined to be near the end of its useful life, the replacement of which would be an Attachment M-3 Project.

6. Candidate EOL Needs List. "Candidate EOL Needs List" shall have the meaning ascribed to it in section (d)(1)(iii).

7. Form No. 715 EOL Planning Criteria. "Form No. 715 EOL Planning Criteria" shall mean planning criteria filed by a Transmission Owner in FERC Form No. 715 to address EOL Needs. No Transmission Owner may be compelled to file a Form No. 715 EOL Planning Criteria not required to be filed pursuant to FERC regulations applicable to Form No. 715.

8. Attachment M-3 EOL Planning Criteria. "Attachment M-3 EOL Planning Criteria" shall mean planning criteria utilized by a Transmission Owner under Attachment M-3 to address EOL Needs.

9. PJM Planning Criteria Need. "PJM Planning Criteria Need" shall mean a need to plan a transmission expansion or enhancement of Transmission Facilities other than those reserved to each Transmission Owner in accordance with section (a).

10. RTEP Planning Process. "RTEP Planning Process" shall mean the process by which PJM develops the Regional Transmission Expansion Plan under ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19.

(c) Procedures for Review of Attachment M-3 Projects. The following procedures shall be applicable to the planning of Attachment M-3 Projects:

1. **Review of Attachment M-3 Projects.** As described in sections 1.3(c) and (d) of ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19, the Subregional RTEP Committees shall be responsible for the review of Attachment M-3 Projects. The Subregional RTEP Committees shall have a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for Attachment M-3 Projects. Disputes shall be resolved in accordance with the dispute resolution procedures set forth in the Tariff or the Consolidated Transmission Owners Agreement, as applicable ~~at Schedule 5 of the Operating Agreement~~. For purposes of this section (c), reference to the Subregional RTEP Committees shall be deemed to include the Transmission Expansion Advisory Committee (TEAC) when the TEAC reviews Attachment M-3 Projects in accordance with these procedures.

2. **Review of Assumptions and Methodology.** In accordance with sections 1.3(d), 1.5.4(a), and 1.5.6(b) and 1.5.6(c) of ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting to review the criteria, assumptions, and models Transmission Owners propose to use to plan and identify Attachment M-3 Projects (Assumptions Meeting). Each Transmission Owner shall provide the criteria, assumptions, and models to PJM for posting at least 20 days in advance of the Assumptions Meeting to provide Subregional RTEP Committee Participants sufficient time to review this information. Stakeholders may provide comments on the criteria, assumptions, and models to the Transmission Owner for consideration either prior to or following the Assumptions Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Assumptions Meeting and may respond or provide feedback as appropriate.

3. **Review of System Needs.** No fewer than 25 days after the Assumptions Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review the identified criteria violations and resulting system needs, if any, that may drive the need for an Attachment M-3 Project (Needs Meeting). Each Transmission Owner will review the identified system needs and the drivers of those needs, based on the application of its criteria, assumptions, and models that it uses to plan Attachment M-3 Projects. The Transmission Owners shall share and post their identified criteria violations and drivers no fewer than 10 days in advance of the Needs Meeting. Stakeholders may provide comments on the criteria violations and drivers to the Transmission Owner for consideration prior to, at, or following the Needs Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Needs Meeting and may respond or provide feedback as appropriate.

4. **Review of Potential Solutions.** No fewer than 25 days after the Needs Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review potential solutions for the identified criteria violations (Solutions Meeting). The Transmission Owners shall share and post their potential solutions, as well as any alternatives identified by the Transmission Owners or stakeholders, no fewer than 10 days in advance of the Solutions Meeting. Stakeholders may provide comments on the potential solutions to the Transmission Owner for consideration either prior to or following the Solutions Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the meeting and may respond or provide feedback as appropriate.

5. **Submission of Attachment M-3 Projects.** Each Transmission Owner will finalize for submittal to the Transmission Provider Attachment M-3 Projects for inclusion in the Local Plan in accordance with section 1.3 of ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19 and the schedule established by the Transmission Provider. Stakeholders may provide comments on the Attachment M-3 Projects in accordance with section 1.3 of ~~Schedule 6 of the PJM Operating Agreement~~Tariff, Schedule 19 before the Local Plan is integrated into the Regional Transmission Expansion Plan. Stakeholders shall have at least 10 days to comment on the Local Plan after the solutions selected by the Transmission Owner for inclusion in the Local Plan are posted. Each Transmission Owner shall review and consider comments that are received at least 10 days before the Local Plan is submitted for integration into the Regional Transmission Expansion Plan.

6. **Information Relating to Attachment M-3 Projects.** Information relating to each Transmission Owner's Attachment M-3 Projects will be provided in accordance with, and subject to the limitations set forth in, section 1.5.4 of ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19. Local Plan Information will be provided to and posted by the Office of Interconnection as set forth in section 1.5.4(e) of ~~Schedule 6 of the Operating Agreement~~Tariff, Schedule 19.

7. **No Limitation on Additional Meetings and Communications or Use of Attachment M-3 For Other Transmission Projects.**

   i. Nothing in this Attachment M-3 precludes any Transmission Owner from agreeing with stakeholders to additional meetings or other communications regarding Attachment M-3 Projects, in addition to the Subregional RTEP Committee process.

ii. Nothing in this Attachment M-3 precludes a Transmission Owner from using the procedures set forth in section (c) to solicit stakeholder input in the planning of Transmission Facilities not subject to this section (c) or the RTEP Planning Process.

(d) Additional Procedures for the Identification and Planning of EOL Needs.

1. **EOL Need Planning Criteria Documentation and Identification**

i. Each PJM Transmission Owner shall develop documentation for its Attachment M-3 EOL Planning Criteria and/or its Form 715 EOL Planning Criteria through which each identifies EOL Needs.

ii. Each Transmission Owner's Attachment M-3 EOL Planning Criteria and/or Form 715 EOL Planning Criteria shall be clearly and separately delineated and presented by the Transmission Owner at least once annually pursuant to section (c)(2) and/or in its FERC Form No. 715 at a meeting of the TEAC.

iii. Annually, each Transmission Owner will provide to PJM a Candidate EOL Needs List comprising its non-public confidential, non-binding projection of up to 5 years of EOL Needs that it has identified under the Transmission Owner's processes for identification of EOL Needs documented under section (d)(1)(i). Each Transmission Owner may change its projection as it deems necessary and will update it annually. Any Candidate EOL Needs List provided to PJM shall remain confidential within PJM, except to the extent necessary for PJM to make the determination referenced in clause (a) of section (d)(2)(ii).

2. **Coordination of EOL Needs Planning With PJM Planning Criteria Needs**.

i. If, as part of the RTEP Planning Process, PJM initially determines that a substantial electrical overlap exists such that a single Solution may address a validated PJM Planning Criteria Need(s) identified during the current PJM planning cycle under the RTEP Planning Process and address a projected EOL Need on the Candidate EOL Needs List, which the relevant Transmission Owner has confirmed remains a projected EOL Need, the relevant Transmission Owner shall consult with PJM regarding such potential overlap.

ii. If, (a) PJM determines through the RTEP Planning Process that a proposed Required Transmission Enhancement would more efficiently and cost-effectively address the identified PJM Planning Criteria Need and may, as well, address the projected EOL Need confirmed under section (d)(2)(i), and (b) the proposed Required Transmission Enhancement is not a solution proposed by the Transmission Owner pursuant to section (c)(4), and (c) the Transmission Owner determines that the projected EOL Need is not met by the proposed Required Transmission Enhancement and determines that it will plan an Attachment M-3 Project to address the projected EOL Need or propose a project to address the Form No. 715 EOL Planning Criteria, the Transmission Owner will provide documentation to PJM and stakeholders on the rationale supporting its determination at the next appropriate meeting of the TEAC or Subregional RTEP Committee that considered the proposed Required Transmission Enhancement.

(e) **Modifications.** This Attachment M-3 may only be modified under section 205 of the Federal Power Act if the proposed modification has been authorized by the PJM Transmission Owners Agreement-Administrative Committee in accordance with section 8.5 of the Consolidated Transmission Owners Agreement.

ATTACHMENT M-4

SPECIAL PROCEDURES SOLELY APPLICABLE TO PLANNING OF CIP-014 MITIGATION SUPPLEMENTAL PROJECTS

a) **Purpose, Limited Scope, Sunset, and Definitions.** Under NERC Reliability Standard CIP-014-2 ("CIP-014"), as it may be redesignated from time to time, Transmission Owners are required to develop and implement physical security plans to protect certain critical transmission stations and substations. This Attachment M-4 is to identify an efficient and cost-effective process for the elimination of such stations and substations as CIP-014 facilities through Supplemental Projects without the level of public disclosure of the existence, location, exact number, and vulnerabilities associated with the CIP-014 facilities that would otherwise be required pursuant to Attachment M-3. The Supplemental Projects that are to be planned for the elimination of CIP-014 stations and substations in accordance with this Attachment M-4, defined below as CIP-014 mitigation projects ("CMP") in Step 1 of this Attachment M-4, are removed from the Attachment M-3 public planning process in order to ensure that security is maintained while also providing reasonable transparency into the planning process and justification for CMPs. This Attachment M-4 mechanism is a limited alternative to the Attachment M-3 process both in scope and duration, is narrowly tailored to meet security needs, and provides for vital roles by both PJM Interconnection, L.L.C. ("PJM") and State Commissions in all CMP Process Steps, as set forth below. Notwithstanding the procedures provided for in Attachment M-3 or other planning requirements with respect to all other Supplemental Projects, including proposed project reviews by the Transmission Expansion Advisory Committee or Subregional RTEP Committees and inclusion in the Local Plan, this Attachment M-4 provides special targeted procedures that the Transmission Owners and the unaffiliated verifying entity as defined in NERC CIP-014 (currently, PJM), shall follow in connection with CMPs, which have the specific purpose of removing transmission stations or substations from the list of CIP-014 facilities, within the limited period for which this Attachment M-4 shall be in effect pursuant to the Sunset provision and Step 1 of this Attachment M-4. Other than to the extent that CMP information is included in models maintained by the Transmission Provider, this information shall be made available to the public during the planning and construction of the CMP only under the confidentiality provisions described in Steps 8 and 10 below. Provisions for confidential consultations with State Commissions during this process are also included herein.

b) **CMP Process Steps.** The process under this Attachment M-4 consists of the following steps:

1. Definition of CMPs. For purposes of this Attachment M-4, a CMP shall mean a "Supplemental Project," as defined in the ~~Operating Agreement, Section 1.42A.02~~Tariff, that is (a) designed specifically to remove a transmission station or

substation from the list of CIP-014 facilities identified as of September 30, 2018 as requiring a documented physical security plan (“CIP-014 List”); and (b) reviewed by PJM in accordance with Step 4 of this Attachment M-4. The intent is to complete CMPs no later than five (5) years after the date that the Commission issues an Order accepting this Attachment M-4.

2. Limitation on the Number of CMPs. The number of stations and substations throughout the PJM region eligible for CMPs will not exceed 20, the maximum allowable under the finite list referred to in Step 1 of this Attachment M-4. The process set forth in this Attachment M-4 shall be in effect and available only as to CMPs designed specifically to remove a transmission station or substation from the list of CIP-014 facilities as it exists on September 30, 2018 and will cease to apply to any transmission station or substation if it is removed or eliminated from that list immediately upon such removal or elimination.

3. Transmission Owner Deliberative Process. A Transmission Owner will submit to PJM:

   A. **Potential Solutions.** The potential alternative means of eliminating a transmission station or substation from the CIP-014 List; and

   B. **Preferred Solution.** Identification from among the Potential Solutions the solution that in the view of the Transmission Owner constitutes the more efficient or cost-effective solution to enable the transmission station or substation to be removed from the list of CIP-014 facilities along with an explanation of its Preferred Solution that addresses the following:

      i. The customer impact that would result from the loss of the transmission station or substation on the CIP-014 List, taking into account any plans for recovering from the loss of the transmission station or substation that could help to restore all or some of the load that was lost, the amount of time that it would take for such load to be restored and the nature of the load to be recovered or not able to be recovered;

      ii. Whether there are distribution system-level solutions to eliminate the transmission station or substation from the CIP-014 List; and

      iii. Whether the Preferred Solution requires new or expanded right-of-way.

4. PJM Review and Assessment.

   A. PJM Review. Upon receiving the Preferred Solution and Potential Solutions from a Transmission Owner pursuant to Step 3 above, PJM (or consultants selected by PJM) shall evaluate those solutions. PJM shall report its findings to the

Transmission Owner in writing and either: (i) advise that the Preferred Solution is the more efficient or cost effective solution from among the Preferred Solutions and Potential Solutions; (ii) suggest modifications to any of the Preferred Solution or Potential Solutions that will permit PJM to advise that one of them is the more efficient or cost effective solution; or (iii) advise that a CMP solution not be pursued. PJM's report of its findings shall include an explanation of the basis for its advice.

B. PJM Assessment and Verification. For any CMP project ultimately selected for construction by the Transmission Owner ("Proposed CMP"), PJM shall assess and verify (or explain its inability to verify) that the project:

i. Will result in removal of one or more transmission stations or substations from the CIP-014 List;

ii. Does not remove transmission station(s) or substation(s) from the CIP-014 List that would otherwise be removed from the list through the current Regional Transmission Expansion Planning Process under the ~~Operating Agreement, Schedule 6~~Tariff, Schedule 19 ("RTEP Process");

iii. Does not provide a solution to address a reliability, operational performance, market efficiency or public policy need that would otherwise be addressed through the current RTEP Process;

iv. Will not result in another transmission station or substation being added to the CIP-014 List; and

v. Does not result in reliability or operational performance criteria violations under the RTEP Process.

PJM shall report its assessment of these factors to the Transmission Owner in writing. No CMP solution shall proceed to another step in the Attachment M-4 process until this Step 4 has been completed. Once PJM and the Transmission Owner have agreed that the report is final, PJM's report will be provided to the affected State Commission, at that agency's option.

5. Consultation with State Commissions. The Transmission Owner shall ensure that all consultations with a State Commission as set forth in this Step 5, are subject to appropriate confidential safeguards. The Transmission Owner shall only be required to engage in consultations with a State Commission with respect to the planning and construction of a CMP under Step 5 and the Transmission Owner and PJM shall only consult with or provide information to a State Commission under Steps 5 or 6, if and to the extent that the Transmission Owner can ensure that such consultations and information will be subject to such appropriate confidential safeguards.

A. Any Transmission Owner having submitted to PJM a Preferred Solution and Potential Solutions to eliminate a transmission station or substation from the CIP-014 List pursuant to Step 3 above shall seek to meet with any State Commission(s) with jurisdiction in the Transmission Zones in which a CMP is proposed to be located. PJM shall be invited to participate in any such meeting. Topics for discussion shall include, but not be limited to the considerations specified in CIP-014, including the need for a CMP, the Potential Solutions submitted to PJM, and the Transmission Owner's Preferred Solution.

B. Upon PJM's completion of the review specified in Step 4 above, the Transmission Owner shall again seek to meet with any State Commission(s) with jurisdiction in the Transmission Zones in which a CMP is proposed to be located. PJM shall be invited to participate in any such meeting. Topics for discussion shall include, but not be limited to PJM's review and findings, including the efficiency and cost-effectiveness of any and all of PJM's recommendations.

C. After identifying and selecting its Proposed CMP pursuant to completion of Step 4(B) above, but before construction is initiated, the Transmission Owner shall further seek to meet with any State Commission(s) with jurisdiction in the Transmission Zones in which the Proposed CMP is to be constructed. PJM shall be invited to participate in any such meeting. Topics for discussion shall include, but not be limited to PJM's assessment of the factors in Step 4(B)(i) through (v) above, the rationale for, location of, and specifications of the Proposed CMP and potential siting issues, particularly those that could affect the estimated project cost. To facilitate the discussion and enable an understanding of the benefits of costs assessed, the Transmission Owner shall be prepared to present an explanation of the reasons and rationale for its intention to proceed to construct its Proposed CMP and the reasonableness of that proposal. The Transmission Owner shall be prepared to address the following:

   i. The customer impact that would result from the loss of the transmission station or substation on the CIP-014 List, taking into account any plans for recovering from the loss of the transmission station or substation that could help to restore all or some of the load that was lost, the amount of time that it would take for such load to be restored and the nature of the load to be recovered or not able to be recovered, as compared to these same factors as they relate to that station or substation assuming that the Proposed CMP is constructed;

   ii. Whether there exist distribution system-level solutions, or changes in operating procedures, or some combination, to eliminate the transmission station or substation from the CIP-014 List;

   iii. Whether the Proposed CMP requires new or expanded right-of-way;

iv. Whether the Proposed CMP will displace costs associated with maintaining physical security for stations/substations on the CIP-014 List; and

v. The estimated cost of the Proposed CMP.

6. PJM Interim/Periodic Review and Interim Consultation with State Commissions. Nothing in this Attachment M-4 precludes PJM, at its sole discretion, from conducting additional periodic examinations to verify the continuing validity of its findings and assessment under Step 4, above. Similarly, nothing in this Attachment M-4 precludes PJM from consulting with State Commissions in addition to those consultations specified in Step 5 above, with or without the participation of the relevant Transmission Owner.

7. Project Notification and Compliance.

   A. Transmission Owner Notification to PJM. Upon satisfaction of all parts of Step 5, the Transmission Owner shall notify PJM in writing that the Proposed CMP will be constructed and identify the location and specifications of the Proposed CMP selected. The Transmission Owner shall make a reasonable effort to seek alternative funding to offset project costs, including but not limited to U.S. Department of Energy grants associated with addressing national security, critical infrastructure or resilience.

   B. Compliance. The Transmission Owner will comply with all applicable licensing, permitting, siting, or certification requirements as well as all applicable proceedings for eminent domain authority.

8. CMP Construction. During construction of a CMP, the Transmission Owner carrying out such construction shall continue to take safeguards to ensure necessary confidentiality until the CMP is placed in service.

9. CMP In-Service Placement. A Transmission Owner shall have complied with all of its obligations set forth in the CMP Process Steps above before the CMP may be placed in-service.

10. Confidentiality. If at any step in the Attachment M-4 process, the level of needed confidentiality is eliminated with respect to elements of CMP information, such confidentiality shall be reduced or lifted. As a precondition to any Transmission Owner being eligible for recovery of the costs of the CMP, the Transmission Owner shall provide public notice of the existence of the CMP.

11. Public Review of CMP. At no time prior to the existence of the CMP being made known to the public by adherence to Step 10 of this Attachment M-4 shall the costs of any CMP be eligible for inclusion in rates filed by any Transmission Owner. After

notice of the existence of a CMP has been provided by adherence to Step 10 of this Attachment M-4, the Transmission Owner may propose to recover its investment in the CMP and the associated costs from Responsible Customers in its Zone through a rate, including a formula rate, in effect under the applicable Tariff, Attachment H similar to the cost recovery process it follows for other Supplemental Projects. Any such proposal shall be subject to discovery on all matters pursuant to the procedures applicable under the applicable Attachment H, the Federal Power Act, and the Commission's regulations, including any applicable procedures for the protection against disclosure of commercially sensitive information and Critical Energy Infrastructure Information.

c) **Modifications.** This Attachment M-4 may be modified under Section 205 of the Federal Power Act only if the proposed modification has been authorized by the PJM Transmission Owners Agreement-Administrative Committee in accordance with Section 8.5 of the Consolidated Transmission Owners Agreement ("CTOA").

d) **Sunset.** This Attachment M-4 terminates five years after the issuance date of an Order from the Federal Energy Regulatory Commission approving this Attachment M-4 for inclusion in the PJM Tariff; however, CMPs already under construction as of that date of termination may proceed and the conditions in Steps 8, 9, 10, and 11 shall remain in force. For any CMP construction occurring after the sunset date, quarterly status briefings shall be provided to any State Commission previously consulted under Step 5 until the CMP is placed in service pursuant to Step 9.

Attachment B

Revisions to the
PJM Open Access Transmission
Tariff

(Clean Format)

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 Tariff, Schedule 19 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"). Tariff, Schedule 19, 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 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 Tariff, Schedule 19, 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.

(6) Except as provided in this subsection, no cost responsibility shall be assigned to a Responsible Zone unless the magnitude of the distribution factor is greater than or equal to 0.01, and any distribution factor of a smaller magnitude shall be set equal to zero. This rule shall not apply to the Zone(s) in which the Required Transmission Enhancement is located, which shall be assigned cost responsibility based on its distribution factor, regardless of the magnitude.

(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 Tariff, Schedule 19, 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 Tariff, Schedule 19, 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 Tariff, Schedule 19, 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 Tariff, Schedule 19, 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) and (b)(v) 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 Tariff, Schedule 19, 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 Tariff, Schedule 19, 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) <u>Assignment of Proportional Multi-Driver Project Costs</u>. 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 Tariff, Schedule 19, 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) <u>Assignment of Incremental Multi-Driver Project Costs</u>. The Transmission Provider shall assign cost responsibility for Incremental Multi-Driver Projects as defined in Tariff, Schedule 19, 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 Tariff, Schedule 19, 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 Tariff, Schedule 19, section 1.5.8(n), were not included in an Tariff, Schedule 19, 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.

(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.

SCHEDULE 12 – APPENDIX A

Required Transmission Enhancements Approved By The PJM Board On Or After February 1, 2013, Responsible Customers And Associated Transmission Owner Revenue Requirements.

This Schedule 12 – Appendix A applies only to the assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider on or after February 1, 2013, or (2) applicable to Required Transmission Enhancements approved by the PJM Board on or after such effective date.

Required Transmission Enhancements that have been placed in service in PJM, the Transmission Owner(s) responsible for constructing and owning and/or financing such Required Transmission Enhancements, the Responsible Customers and the annual revenue requirement upon which Transmission Enhancement Charges determined in accordance with section (c) of Schedule 12 are based, are set forth below. Unless otherwise stated, all designations of Responsible Customers refer collectively to all Firm Point-to-Point Transmission Service and Network Integration Transmission Service customers in each indicated Zone and state the proportional (percentage) cost responsibility allocated to the indicated customers in each Zone. Zones are identified using the short names stated in Attachment J to the Tariff.

SCHEDULE 12 – APPENDIX B

Joint Planning Or Coordination Agreements Between PJM And Other Regions Or Transmission Planning Authorities

1. Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., which can be found at miso-joa.pdf (pjm.com);

2. Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. and The Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol, which can be found at https://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx;

3. Interregional transmission coordination between Southeastern Regional Transmission Planning region participants and PJM pursuant to Tariff, Schedule 12-B and Schedule 19-A and the corresponding provisions of the tariffs of the jurisdictional Southeastern Regional Transmission Planning region participants;

4. Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., which is found at nyiso-joa.ashx (pjm.com);

5. Joint Reliability Coordination Agreement among and between Tennessee Valley Authority, Louisville Gas and Electric Co. and Kentucky Utilities Co., and PJM Interconnection, L.L.C., which can be found at joint-reliability-agreement-jrca-pjm-tva.ashx;

6. Adjacent Reliability Coordinator Coordination Agreement between PJM Interconnection, L.L.C. VACAR South RC, those being Duke Energy Progress, Inc., Duke Energy Carolinas, LLC, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas, LLC, which can be found at https://www.pjm.com/-/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx; and

7. Amended and Restated Agreement Joint Operating Agreement Among and Between PJM Interconnection L.L.C., and Duke Energy Progress, L.L.C, which is found at progress-joa.pdf (pjm.com).

Schedule 12 - Appendix C

State Agreement Public Policy Projects Constructed Pursuant to the State Agreement Approach

This Schedule 12 - Appendix C applies only to the assignment of cost responsibility of State Agreement Public Policy Projects constructed in accordance with Tariff, Schedule 19, section 1.5.9 among Responsible Customers.

(1) Rate Schedule FERC No. 49, State Agreement Approach Agreement By and Among PJM Interconnection, L.L.C. and New Jersey Board of Public Utilities

In accordance with the FERC order in Docket Nos. ER22-2690-000 and -001, 181 FERC ¶ 61,178 (2022), cost responsibility for the State Agreement Public Policy Projects shall be assigned annually on a load-ratio share basis among Network Customers in the State of New Jersey determined in accordance with Schedule 12, section (c)(4), and customers using Point-to-Point Transmission Service with a Point of Delivery within the State of New Jersey determined in accordance with Schedule 12, section (c)(5), as follows:

With respect to each Zone located in the State of New Jersey, 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.

Identifier	Description	Responsible Customers (percentage share)
b3737.1	Reconfigure Larrabee 230 kV substation	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.2	Larrabee substation – 230 kV equipment for direct connection	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.3	Lakewood Generator substation – Update relay settings on the Larrabee 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.4	B54 Larrabee – South Lockwood 34.5 kV line transfer	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.5	Larrabee Collector station – Larrabee 230 kV new line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.6	Larrabee Collector station – Smithburg No.1 500 kV line (new asset). New 500 kV line will be built double circuit to accommodate a 500 kV line and a 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.7	Rebuild G1021 Atlantic – Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500 kV/230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.8	Smithburg substation 500 kV expansion to 4-breaker ring	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.9	Larrabee substation upgrades	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.10	Atlantic 230 kV substation – Convert to double-breaker double-bus	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.11	Freneau substation – Update relay settings on the Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.12	Smithburg substation – Update relay settings on the Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.13	Oceanview substation – Update relay settings on the Atlantic 230 kV lines	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.14	Red Bank substation – Update relay settings on the Atlantic 230 kV lines	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.15	South River substation – Update relay settings on the Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.16	Larrabee substation – Update relay settings on the Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.17	Atlantic substation – Construct a new 230 kV line terminal position to accept the generator lead line from the offshore wind Larrabee Collector station	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.18	G1021 (Atlantic – Smithburg) 230 kV upgrade	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.19	R1032 (Atlantic – Larrabee) 230 kV upgrade	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.20	New Larrabee Collector station – Atlantic 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.21	Larrabee – Oceanview 230 kV line upgrade	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.22	Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 bay breaker and a half substation with a nominal current rating of 4000 A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.23	Rebuild the underground portion of Richmond – Waneeta 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.24	Upgrade Cardiff – Lewis 138 kV by replacing 1590 kcmil strand bus inside Lewis substation	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.25	Upgrade Lewis No. 2 – Lewis No. 1 138 kV by replacing its bus tie with 2000 A circuit breaker	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.26	Upgrade Cardiff – New Freedom 230 kV by modifying existing relay setting to increase relay limit	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.27	Rebuild approximately 0.8 miles of the D1018 (Clarksville –Lawrence 230 kV) line between Lawrence substation (PSEG) and structure No. 63	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.28	Reconductor Kilmer I – Lake Nelson I 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.29	Convert the six-wired East Windsor – Smithburg E2005 230 kV line (9.0 miles) to two circuits: One a 500 kV line and the other a 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.30	Add third Smithburg 500/230 kV transformer	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.31	Additional reconductoring required for Lake Nelson I –Middlesex 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.32	Rebuild Larrabee – Smithburg No. 1 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.33	Reconductor Red Oak A – Raritan River 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.34	Reconductor Red Oak B – Raritan River 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.35	Reconductor small section of Raritan River – Kilmer I 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.36	Replace substation conductor at Kilmer and reconductor Raritan River – Kilmer W 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.37	Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run – Hope Creek 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.38	Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV switching station, and relocate the Linden – Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV station	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.39	Bergen subproject: Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.40	Windsor to Clarksville subproject: Create a paired conductor path between Clarksville 230 kV and JCPL Windsor Switch 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.41	Windsor to Clarksville subproject: Upgrade all terminal equipment at Windsor 230 kV and Clarksville 230 kV as necessary to create a paired conductor path between Clarksville and JCPL East Windsor Switch 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.42	Upgrade inside plant equipment at Lake Nelson I 230 kV station	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.43	Upgrade Kilmer W – Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.44	Upgrade Lake Nelson – Middlesex – Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.45	Reconductor 0.33 miles of PPL's portion of the Gilbert –Springfield 230 kV line	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.46	Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

Identifier	Description	Responsible Customers (percentage share)
b3737.47+	Build a new North Delta 500 kV substation with four bay breaker and half configuration. The substation will include 12 500 kV breakers and one 500/230 kV transformers, will allow the termination of six 500 kV lines	**Reliability Driver (26.73%):** **Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS (5.76%) / ATSI (8.04%) / BGE (4.11%) / ComEd (13.39%) / Dayton (2.12%) / DEOK (3.25%) / DL (1.71%) / Dominion (13.32%) / DPL (2.60%) / EKPC (1.89%) / JCPL (3.86%) / ME (1.90%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.40%) / PENELEC (1.78%) / PEPCO (3.67%) / PPL (4.72%) / PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** PECO (100%) **Public Policy Driver (73.27%):** AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.48	Build a new North Delta – Graceton 230 kV line by rebuilding 6.07 miles of the existing Cooper – Graceton 230 kV line to double circuit	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.49	Bring the Cooper – Graceton 230 kV line "in and out" of North Delta by constructing a new double-circuit North Delta – Graceton 230 kV (0.3 miles) and a new North Delta – Cooper 230 kV (0.4 miles) cut-in lines	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)

+ b3737.47 is an Incremental Multi-Driver Project that includes both a reliability driver and a public policy driver. Accordingly, b3737.47 is included on both Tariff, Schedule 12–Appendix A, section 28 and Tariff, Schedule 12–Appendix C, section 1.

Identifier	Description	Responsible Customers (percentage share)
b3737.50	Bring the Peach Bottom – Delta Power Plant 500 kV line “in and out” of North Delta by constructing a new Peach Bottom – North Delta 500 kV (0.3 miles) cut-in and cut-out lines	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.51	Replace four 63 kA circuit breakers "205," "235," "225" and "255" at Peach Bottom 500 kV with 80 kA	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.52	Replace one 63 kA circuit breaker "B4" at Conastone 230 kV with 80 kA	AEC (13.64%) / JCPL (31.98%) / PSEG (52.17%) / RE (2.21%)
b3737.53	Remove the existing E83 115 kV line (not in-service) to accommodate the new 500 kV/230 kV lines (approximately 7.7 miles)	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.54	Remove the existing H2008 Larrabee – Smithburg No. 2 230 kV line to accommodate the new 500 kV/230 kV lines	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.55	Middlesex substation 230 kV – Replace the 2000A circuit switcher at Middlesex switch point for the Lake Nelson I1023 230 kV exit	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.56	Build a new North Delta – Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper – Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO and BGE. This subproject is for BGE's portion of the line rebuild, which is 2.16 miles	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.59	Windsor to Clarksville subproject: Upgrade terminal equipment at Windsor 230 kV station	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)
b3737.60	Perform a Pre-build Infrastructure evaluation study in alignment with the NJBPU Solicitation Guidance Document requirements	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)

SCHEDULE 12-B

Allocation of Costs of Certain Interregional Transmission Projects Located in the PJM and SERTP Regions

1. **Cost Allocation:** The PJM Region portion determined under Section 3 of this Schedule 12-B of the cost of an interregional transmission project located in the PJM Region and the Southeastern Regional Transmission Planning Process ("SERTP") region shall be allocated in accordance with Schedule 12 of the Tariff, provided that the interregional transmission project satisfies all of the criteria in Section 2 of this Schedule 12-B.

2. **Proposal of Interregional Transmission Projects for Interregional Cost Allocation Purposes:** For an interregional transmission project to be eligible for interregional cost allocation purposes within the SERTP region and the PJM Region, all of the following criteria must be met:

A. The interregional transmission project must be interregional in nature, which requires that it must:

- Be physically located in both the SERTP region and the PJM Region;
- Interconnect to transmission facilities in both the PJM and SERTP regions. The facilities to which the project is proposed to interconnect may be either existing transmission facilities or transmission projects included in the regional transmission expansion plan that are currently under development; and
- Meet the threshold criteria for transmission projects potentially eligible to be included in the regional transmission plans for purposes of cost allocation in both the SERTP region and the PJM Region, pursuant to the regional transmission planning process of the SERTP region and the Regional Transmission Expansion Plan prepared by the Office of the Interconnection pursuant to Tariff, Schedule 19, respectively.

B. The interregional transmission project must be proposed for purposes of cost allocation in both the SERTP region and the PJM Region:

- The transmission developer and project submittal must satisfy all criteria specified in the respective regional transmission processes; and
- The proposal should be submitted in the timeframes outlined in the respective regional transmission planning processes.

C. The interregional transmission project must be selected both in the regional transmission plan of the SERTP region and in the Regional Transmission Expansion Plan prepared by the Office of the Interconnection for the PJM Region:

- The costs of the interregional transmission project eligible for interregional cost allocation shall only be allocated to a region if that region has selected the interregional transmission project in its regional transmission plan for purposes of cost allocation; and

- No cost shall be allocated to a region that has not selected the interregional transmission project in its regional transmission plan for purposes of cost allocation.

3. **Allocation of Costs for Interregional Transmission Projects Between the SERTP and PJM Regions:** The cost of an interregional transmission project selected for purposes of cost allocation in the regional transmission plans of both the SERTP region and PJM Region shall be allocated for interregional cost allocation purposes to those regions as provided below:

A. The share of the costs of an interregional transmission project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region's displaced regional transmission project(s) to the total of the present values of the estimated costs of the displaced regional transmission projects in all regions that have selected the interregional transmission project in their regional transmission plans for purposes of cost allocation. The present values used in the cost allocation shall be based on a common date, comparable cost components, and the latest cost estimates used in the determination to include the interregional transmission project in the respective regional plans for purposes of cost allocation. The applicable discount rate(s) used for the SERTP region for interregional cost allocation purposes will be based upon the after-tax weighted average cost of capital of the SERTP transmission owners whose projects would be displaced by the proposed interregional transmission project. The applicable discount rate for the PJM Region shall be the discount rate included in the assumptions that are reviewed with the PJM Board of Managers each year for use in the economic planning process.

B. When all or a portion of an interregional transmission project is to be located within a region in which there is no displaced regional transmission project, such region may, at its sole discretion, select the interregional transmission project for inclusion in its regional transmission plan; provided, however, that no portion of the costs of the interregional transmission project shall be allocated to such region pursuant to Section 3(A).

C. Nothing in this Schedule 12-B shall govern the further allocation of costs allocated to a region pursuant to this Section 3 within such region. For purposes of clarification, the further allocation of costs allocated by this Section 3 within the PJM Region shall be governed by the applicable provisions of Schedule 12 of the Tariff.

D. The following example illustrates the cost allocation provisions in Section 3:

- Regions A and B, through the joint evaluation process prescribed in Tariff, Schedule 19-A have included Transmission Project Z in their respective regional plans for purposes of cost allocation. Transmission Project Z was determined to address both regions' needs more efficiently or cost effectively than Transmission Project X in Region A and Transmission Project Y in Region B.
- The estimated cost of Transmission Projects X and Y are Cost (X) and Cost (Y) respectively. As described in Section 3(A), these costs shall be based upon common cost components.

- The number of years from the common present value date to the year associated with the cost estimates of Transmission Projects X and Y are N(X) and N(Y) respectively.
- Recognizing that the regions may have different discount rates, for purposes of this example D_A is the discount rate used for Transmission Project X and D_B is the discount rate used for Transmission Project Y.
- Based on the foregoing assumptions and the allocation of costs based upon displaced regional transmission projects as prescribed in Section 3(A), the following illustrative formulas would be used:
  - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+ D_A)^{N(X)}$
  - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+ D_B)^{N(Y)}$
  - Cost Allocation to Region A = PV Cost (X) / [PV Cost (X) + PV Cost (Y)]
  - Cost Allocation to Region B = PV Cost (Y) / [PV Cost (X) + PV Cost (Y)]
- Applying the above formulas, if:
  - Cost (X) = $60 Million and N(X) = 8.25 years
  - Cost (Y) = $40 Million and N(Y) = 4.50 years
  - D_A = 7.5% per year
  - D_B = 7.4% per year

- Then:
  - PV Cost (X) = $60/(1+0.075)^{8.25}$ = 33.0 Million
  - PV Cost (Y) = $40/(1+0.074)^{4.50}$ = 29.0 Million
  - Cost Allocation to Region A = 33.0 / (33.0 + 29.0) = 53.2% of the cost of Transmission Project Z
  - Cost Allocation to Region B = 29.0 / (33.0 + 29.0) = 46.8% of the cost of Transmission Project Z

4. **Merchant Transmission and Transmission Owner Projects:** Nothing in this Schedule 12-B shall preclude the development of interregional transmission projects that are funded by merchant transmission developers or by individual transmission owners.

5. **Exclusivity with Respect to Interregional Transmission Projects Selected for Interregional Cost Allocation Purposes:** The following provisions shall apply regarding other cost allocation arrangements:

A. Except as provided in Section 5(B), the provisions in this Schedule 12-B are the exclusive means by which any costs of an interregional transmission project selected for interregional cost allocation purposes between the SERTP region and the PJM Region may be allocated between or among those regions.

B. A transmission owner(s) or transmission developer(s) may propose to fund or allocate, on a voluntary basis, the cost of an interregional transmission project selected for interregional cost allocation purposes using an allocation other than the allocation that results from the methodology set forth in Section 3, provided that, should the allocation of cost of such interregional transmission project be subject to the Commission's jurisdiction, such allocation proposal is accepted for filing by the Commission in accordance with the filing rights with respect to cost allocation set forth in Section 6 of this Schedule 12-B and provided further that no allocation shall be made to any region that has not agreed to that allocation.

6. **Section 205 Filing Rights with Respect to Interregional Transmission Projects Selected for Interregional Cost Allocation Purposes:** Solely with respect to interregional transmission projects evaluated under Tariff, Schedule 19-A and selected by the SERTP and PJM regional transmission planning processes for purposes of interregional cost allocation purposes, the following provisions shall apply:

A. Except as provided in Sections 5 and 6(B) of this Schedule 12-B, nothing in this Schedule 12-B will convey, expand, limit or otherwise alter any rights of the transmission owners, transmission developers or other market participants to submit filings under Section 205 of the Federal Power Act ("FPA") regarding cost allocation or any other matter.

B. The cost allocation provisions in this Schedule 12-B shall not be modified under Section 205 of the FPA without the mutual consent of the holders of the FPA Section 205 rights with respect to interregional cost allocation in the SERTP region and the PJM Region.

7. **Consequences to Other Regions from Interregional Transmission Projects:** Except as provided in this Schedule 12-B, or in other documents, agreements or tariffs on file with the Commission, neither the PJM Region nor the transmission providers in the SERTP region shall be responsible for compensating another planning region for required upgrades or for any other consequences in another planning region associated with interregional transmission projects identified pursuant to Tariff, Schedule 19-A.

ATTACHMENT
M-3
ADDITIONAL PROCEDURES FOR PLANNING
SUPPLEMENTAL PROJECTS AND ASSET MANAGEMENT PROJECTS

(a) Applicability. Each Transmission Owner shall be responsible for planning and constructing in accordance with Tariff, Schedule 19 as provided in this Attachment M-3, to the extent applicable, (i) Asset Management Projects, as defined herein, (ii) Supplemental Projects, as defined in the Tariff, and (iii) any other transmission expansion or enhancement of Transmission Facilities that is not planned by PJM to address one or more of the following planning criteria:

1. NERC Reliability Standards (which includes Applicable Regional Entity reliability standards);

2. Individual Transmission Owner planning criteria as filed in FERC Form No. 715 and posted on the PJM website, provided that the Additional Procedures for the Identification and Planning of EOL Needs, set forth in section (d), shall apply, as applicable;

3. Criteria to address economic constraints in accordance with section 1.5.7 of Tariff, Schedule 19 or an agreement listed in Schedule 12-Appendix B;

4. State Agreement Approach expansions or enhancements in accordance with section 1.5.9(a)(ii) of Tariff, Schedule 19; or

5. An expansion or enhancement to be addressed by the RTEP Planning Process pursuant to section (d)(2) of this Attachment M-3 in accordance with RTEP Planning Process procedures in Tariff, Schedule 19.

This Attachment M-3 shall not apply to CIP-014 mitigation projects that are subject to Attachment M-4.

(b) Definitions.

1. Asset Management Project. "Asset Management Project" shall mean any modification or replacement of a Transmission Owner's Transmission Facilities that results in no more than an Incidental Increase in transmission capacity undertaken to perform maintenance, repair, and replacement work, to address an EOL Need, or to effect infrastructure security, system reliability, and automation projects the Transmission Owner undertakes to maintain its existing electric transmission system and meet regulatory compliance requirements.

2. Attachment M-3 Project. "Attachment M-3 Project" means (i) an Asset Management Project that affects the connectivity of Transmission Facilities that are included in the Transmission System, affects Transmission Facility ratings or significantly changes the impedance of Transmission Facilities; (ii) a Supplemental Project; or (iii) any other expansion or enhancement of

Transmission Facilities that is not excluded from this Attachment M-3 under any of clauses (1) through (5) of section (a). "Attachment M-3 Project" does not include a project to address Form No. 715 EOL Planning Criteria.

3. Incidental Increase. "Incidental Increase" shall mean an increase in transmission capacity achieved by advancements in technology and/or replacements consistent with current Transmission Owner design standards, industry standards, codes, laws or regulations, which is not reasonably severable from an Asset Management Project. A transmission project that results in more than an Incidental Increase in transmission capacity is an expansion or enhancement of Transmission Facilities.

4. Transmission Facilities. "Transmission Facilities" shall have the meaning set forth in the Consolidated Transmission Owners Agreement.

5. EOL Need. "EOL Need" shall mean a need to replace a transmission line between breakers operating at or above 100 kV or a transformer, the high side of which operates at or above 100 kV and the low side of which is not connected to distribution facilities, which the Transmission Owner has determined to be near the end of its useful life, the replacement of which would be an Attachment M-3 Project.

6. Candidate EOL Needs List. "Candidate EOL Needs List" shall have the meaning ascribed to it in section (d)(1)(iii).

7. Form No. 715 EOL Planning Criteria. "Form No. 715 EOL Planning Criteria" shall mean planning criteria filed by a Transmission Owner in FERC Form No. 715 to address EOL Needs. No Transmission Owner may be compelled to file a Form No. 715 EOL Planning Criteria not required to be filed pursuant to FERC regulations applicable to Form No. 715.

8. Attachment M-3 EOL Planning Criteria. "Attachment M-3 EOL Planning Criteria" shall mean planning criteria utilized by a Transmission Owner under Attachment M-3 to address EOL Needs.

9. PJM Planning Criteria Need. "PJM Planning Criteria Need" shall mean a need to plan a transmission expansion or enhancement of Transmission Facilities other than those reserved to each Transmission Owner in accordance with section (a).

10. RTEP Planning Process. "RTEP Planning Process" shall mean the process by which PJM develops the Regional Transmission Expansion Plan under Tariff, Schedule 19.

(c) Procedures for Review of Attachment M-3 Projects. The following procedures shall be applicable to the planning of Attachment M-3 Projects:

1. **Review of Attachment M-3 Projects.** As described in sections 1.3(c) and (d) of Tariff, Schedule 19, the Subregional RTEP Committees shall be responsible for the review of Attachment M-3 Projects. The Subregional RTEP Committees

shall have a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for Attachment M-3 Projects. Disputes shall be resolved in accordance with the dispute resolution procedures set forth in the Tariff or the Consolidated Transmission Owners Agreement, as applicable. For purposes of this section (c), reference to the Subregional RTEP Committees shall be deemed to include the Transmission Expansion Advisory Committee (TEAC) when the TEAC reviews Attachment M-3 Projects in accordance with these procedures.

2. **Review of Assumptions and Methodology.** In accordance with sections 1.3(d), 1.5.4(a), and 1.5.6(b) and 1.5.6(c) of Tariff, Schedule 19, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting to review the criteria, assumptions, and models Transmission Owners propose to use to plan and identify Attachment M-3 Projects (Assumptions Meeting). Each Transmission Owner shall provide the criteria, assumptions, and models to PJM for posting at least 20 days in advance of the Assumptions Meeting to provide Subregional RTEP Committee Participants sufficient time to review this information. Stakeholders may provide comments on the criteria, assumptions, and models to the Transmission Owner for consideration either prior to or following the Assumptions Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Assumptions Meeting and may respond or provide feedback as appropriate.

3. **Review of System Needs.** No fewer than 25 days after the Assumptions Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review the identified criteria violations and resulting system needs, if any, that may drive the need for an Attachment M-3 Project (Needs Meeting). Each Transmission Owner will review the identified system needs and the drivers of those needs, based on the application of its criteria, assumptions, and models that it uses to plan Attachment M-3 Projects. The Transmission Owners shall share and post their identified criteria violations and drivers no fewer than 10 days in advance of the Needs Meeting. Stakeholders may provide comments on the criteria violations and drivers to the Transmission Owner for consideration prior to, at, or following the Needs Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Needs Meeting and may respond or provide feedback as appropriate.

4. **Review of Potential Solutions.** No fewer than 25 days after the Needs Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review potential solutions for the identified criteria violations (Solutions Meeting). The Transmission Owners shall share and post their potential solutions, as well as any alternatives identified by the Transmission Owners or stakeholders, no fewer than 10 days in advance of the Solutions Meeting. Stakeholders may provide

comments on the potential solutions to the Transmission Owner for consideration either prior to or following the Solutions Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the meeting and may respond or provide feedback as appropriate.

5. **Submission of Attachment M-3 Projects.** Each Transmission Owner will finalize for submittal to the Transmission Provider Attachment M-3 Projects for inclusion in the Local Plan in accordance with section 1.3 of Tariff, Schedule 19 and the schedule established by the Transmission Provider. Stakeholders may provide comments on the Attachment M-3 Projects in accordance with section 1.3 of Tariff, Schedule 19 before the Local Plan is integrated into the Regional Transmission Expansion Plan. Stakeholders shall have at least 10 days to comment on the Local Plan after the solutions selected by the Transmission Owner for inclusion in the Local Plan are posted. Each Transmission Owner shall review and consider comments that are received at least 10 days before the Local Plan is submitted for integration into the Regional Transmission Expansion Plan.

6. **Information Relating to Attachment M-3 Projects.** Information relating to each Transmission Owner's Attachment M-3 Projects will be provided in accordance with, and subject to the limitations set forth in, section 1.5.4 of Tariff, Schedule 19. Local Plan Information will be provided to and posted by the Office of Interconnection as set forth in section 1.5.4(e) of Tariff, Schedule 19.

7. **No Limitation on Additional Meetings and Communications or Use of Attachment M-3 For Other Transmission Projects.**

   i. Nothing in this Attachment M-3 precludes any Transmission Owner from agreeing with stakeholders to additional meetings or other communications regarding Attachment M-3 Projects, in addition to the Subregional RTEP Committee process.

   ii. Nothing in this Attachment M-3 precludes a Transmission Owner from using the procedures set forth in section (c) to solicit stakeholder input in the planning of Transmission Facilities not subject to this section (c) or the RTEP Planning Process.

(d) Additional Procedures for the Identification and Planning of EOL Needs.

1. **EOL Need Planning Criteria Documentation and Identification**

   i. Each PJM Transmission Owner shall develop documentation for its Attachment M-3 EOL Planning Criteria and/or its Form 715 EOL Planning Criteria through which each identifies EOL Needs.

ii. Each Transmission Owner's Attachment M-3 EOL Planning Criteria and/or Form 715 EOL Planning Criteria shall be clearly and separately delineated and presented by the Transmission Owner at least once annually pursuant to section (c)(2) and/or in its FERC Form No. 715 at a meeting of the TEAC.

iii. Annually, each Transmission Owner will provide to PJM a Candidate EOL Needs List comprising its non-public confidential, non-binding projection of up to 5 years of EOL Needs that it has identified under the Transmission Owner's processes for identification of EOL Needs documented under section (d)(1)(i). Each Transmission Owner may change its projection as it deems necessary and will update it annually. Any Candidate EOL Needs List provided to PJM shall remain confidential within PJM, except to the extent necessary for PJM to make the determination referenced in clause (a) of section (d)(2)(ii).

2. **Coordination of EOL Needs Planning With PJM Planning Criteria Needs**.

i. If, as part of the RTEP Planning Process, PJM initially determines that a substantial electrical overlap exists such that a single Solution may address a validated PJM Planning Criteria Need(s) identified during the current PJM planning cycle under the RTEP Planning Process and address a projected EOL Need on the Candidate EOL Needs List, which the relevant Transmission Owner has confirmed remains a projected EOL Need, the relevant Transmission Owner shall consult with PJM regarding such potential overlap.

ii. If, (a) PJM determines through the RTEP Planning Process that a proposed Required Transmission Enhancement would more efficiently and cost-effectively address the identified PJM Planning Criteria Need and may, as well, address the projected EOL Need confirmed under section (d)(2)(i), and (b) the proposed Required Transmission Enhancement is not a solution proposed by the Transmission Owner pursuant to section (c)(4), and (c) the Transmission Owner determines that the projected EOL Need is not met by the proposed Required Transmission Enhancement and determines that it will plan an Attachment M-3 Project to address the projected EOL Need or propose a project to address the Form No. 715 EOL Planning Criteria, the Transmission Owner will provide documentation to PJM and stakeholders on the rationale supporting its determination at the next appropriate meeting of the TEAC or Subregional RTEP Committee that considered the proposed Required Transmission Enhancement.

(e) **Modifications.** This Attachment M-3 may only be modified under section 205 of the Federal Power Act if the proposed modification has been authorized by the PJM Transmission Owners Agreement-Administrative Committee in accordance with section 8.5 of the Consolidated Transmission Owners Agreement.

ATTACHMENT M-4

SPECIAL PROCEDURES SOLELY APPLICABLE TO PLANNING OF CIP-014 MITIGATION SUPPLEMENTAL PROJECTS

a) **Purpose, Limited Scope, Sunset, and Definitions.** Under NERC Reliability Standard CIP-014-2 ("CIP-014"), as it may be redesignated from time to time, Transmission Owners are required to develop and implement physical security plans to protect certain critical transmission stations and substations. This Attachment M-4 is to identify an efficient and cost-effective process for the elimination of such stations and substations as CIP-014 facilities through Supplemental Projects without the level of public disclosure of the existence, location, exact number, and vulnerabilities associated with the CIP-014 facilities that would otherwise be required pursuant to Attachment M-3. The Supplemental Projects that are to be planned for the elimination of CIP-014 stations and substations in accordance with this Attachment M-4, defined below as CIP-014 mitigation projects ("CMP") in Step 1 of this Attachment M-4, are removed from the Attachment M-3 public planning process in order to ensure that security is maintained while also providing reasonable transparency into the planning process and justification for CMPs. This Attachment M-4 mechanism is a limited alternative to the Attachment M-3 process both in scope and duration, is narrowly tailored to meet security needs, and provides for vital roles by both PJM Interconnection, L.L.C. ("PJM") and State Commissions in all CMP Process Steps, as set forth below. Notwithstanding the procedures provided for in Attachment M-3 or other planning requirements with respect to all other Supplemental Projects, including proposed project reviews by the Transmission Expansion Advisory Committee or Subregional RTEP Committees and inclusion in the Local Plan, this Attachment M-4 provides special targeted procedures that the Transmission Owners and the unaffiliated verifying entity as defined in NERC CIP-014 (currently, PJM), shall follow in connection with CMPs, which have the specific purpose of removing transmission stations or substations from the list of CIP-014 facilities, within the limited period for which this Attachment M-4 shall be in effect pursuant to the Sunset provision and Step 1 of this Attachment M-4. Other than to the extent that CMP information is included in models maintained by the Transmission Provider, this information shall be made available to the public during the planning and construction of the CMP only under the confidentiality provisions described in Steps 8 and 10 below. Provisions for confidential consultations with State Commissions during this process are also included herein.

b) **CMP Process Steps.** The process under this Attachment M-4 consists of the following steps:

1. Definition of CMPs. For purposes of this Attachment M-4, a CMP shall mean a "Supplemental Project," as defined in the Tariff, that is (a) designed specifically to remove a transmission station or substation from the list of CIP-014 facilities

identified as of September 30, 2018 as requiring a documented physical security plan ("CIP-014 List"); and (b) reviewed by PJM in accordance with Step 4 of this Attachment M-4. The intent is to complete CMPs no later than five (5) years after the date that the Commission issues an Order accepting this Attachment M-4.

2. Limitation on the Number of CMPs. The number of stations and substations throughout the PJM region eligible for CMPs will not exceed 20, the maximum allowable under the finite list referred to in Step 1 of this Attachment M-4. The process set forth in this Attachment M-4 shall be in effect and available only as to CMPs designed specifically to remove a transmission station or substation from the list of CIP-014 facilities as it exists on September 30, 2018 and will cease to apply to any transmission station or substation if it is removed or eliminated from that list immediately upon such removal or elimination.

3. Transmission Owner Deliberative Process. A Transmission Owner will submit to PJM:

   A. **Potential Solutions.** The potential alternative means of eliminating a transmission station or substation from the CIP-014 List; and

   B. **Preferred Solution.** Identification from among the Potential Solutions the solution that in the view of the Transmission Owner constitutes the more efficient or cost-effective solution to enable the transmission station or substation to be removed from the list of CIP-014 facilities along with an explanation of its Preferred Solution that addresses the following:

      i. The customer impact that would result from the loss of the transmission station or substation on the CIP-014 List, taking into account any plans for recovering from the loss of the transmission station or substation that could help to restore all or some of the load that was lost, the amount of time that it would take for such load to be restored and the nature of the load to be recovered or not able to be recovered;

      ii. Whether there are distribution system-level solutions to eliminate the transmission station or substation from the CIP-014 List; and

      iii. Whether the Preferred Solution requires new or expanded right-of-way.

4. PJM Review and Assessment.

   A. PJM Review. Upon receiving the Preferred Solution and Potential Solutions from a Transmission Owner pursuant to Step 3 above, PJM (or consultants selected by PJM) shall evaluate those solutions. PJM shall report its findings to the Transmission Owner in writing and either: (i) advise that the Preferred Solution is the more efficient or cost effective solution from among the Preferred Solutions and Potential Solutions; (ii) suggest modifications to any of the Preferred Solution or Potential Solutions that will permit PJM to advise that one of them is the more efficient or cost effective solution; or (iii) advise that a CMP solution not be pursued. PJM's report of its findings shall include an explanation of the basis for its advice.

B. PJM Assessment and Verification. For any CMP project ultimately selected for construction by the Transmission Owner ("Proposed CMP"), PJM shall assess and verify (or explain its inability to verify) that the project:

i. Will result in removal of one or more transmission stations or substations from the CIP-014 List;

ii. Does not remove transmission station(s) or substation(s) from the CIP-014 List that would otherwise be removed from the list through the current Regional Transmission Expansion Planning Process under the Tariff, Schedule 19 ("RTEP Process");

iii. Does not provide a solution to address a reliability, operational performance, market efficiency or public policy need that would otherwise be addressed through the current RTEP Process;

iv. Will not result in another transmission station or substation being added to the CIP-014 List; and

v. Does not result in reliability or operational performance criteria violations under the RTEP Process.

PJM shall report its assessment of these factors to the Transmission Owner in writing. No CMP solution shall proceed to another step in the Attachment M-4 process until this Step 4 has been completed. Once PJM and the Transmission Owner have agreed that the report is final, PJM's report will be provided to the affected State Commission, at that agency's option.

5. Consultation with State Commissions. The Transmission Owner shall ensure that all consultations with a State Commission as set forth in this Step 5, are subject to appropriate confidential safeguards. The Transmission Owner shall only be required to engage in consultations with a State Commission with respect to the planning and construction of a CMP under Step 5 and the Transmission Owner and PJM shall only consult with or provide information to a State Commission under Steps 5 or 6, if and to the extent that the Transmission Owner can ensure that such consultations and information will be subject to such appropriate confidential safeguards.

A. Any Transmission Owner having submitted to PJM a Preferred Solution and Potential Solutions to eliminate a transmission station or substation from the CIP-014 List pursuant to Step 3 above shall seek to meet with any State Commission(s) with jurisdiction in the Transmission Zones in which a CMP is proposed to be located. PJM shall be invited to participate in any such meeting. Topics for discussion shall include, but not be limited to the considerations specified in CIP-014, including the need for a CMP, the Potential Solutions submitted to PJM, and the Transmission Owner's Preferred Solution.

B. Upon PJM's completion of the review specified in Step 4 above, the Transmission Owner shall again seek to meet with any State Commission(s) with jurisdiction in the Transmission Zones in which a CMP is proposed to be located. PJM shall be invited to participate in any such meeting. Topics for discussion shall include, but not be limited to PJM's review and findings, including the efficiency and cost-effectiveness of any and all of PJM's recommendations.

C. After identifying and selecting its Proposed CMP pursuant to completion of Step 4(B) above, but before construction is initiated, the Transmission Owner shall further seek to meet with any State Commission(s) with jurisdiction in the Transmission Zones in which the Proposed CMP is to be constructed. PJM shall be invited to participate in any such meeting. Topics for discussion shall include, but not be limited to PJM's assessment of the factors in Step 4(B)(i) through (v) above, the rationale for, location of, and specifications of the Proposed CMP and potential siting issues, particularly those that could affect the estimated project cost. To facilitate the discussion and enable an understanding of the benefits of costs assessed, the Transmission Owner shall be prepared to present an explanation of the reasons and rationale for its intention to proceed to construct its Proposed CMP and the reasonableness of that proposal. The Transmission Owner shall be prepared to address the following:

    i. The customer impact that would result from the loss of the transmission station or substation on the CIP-014 List, taking into account any plans for recovering from the loss of the transmission station or substation that could help to restore all or some of the load that was lost, the amount of time that it would take for such load to be restored and the nature of the load to be recovered or not able to be recovered, as compared to these same factors as they relate to that station or substation assuming that the Proposed CMP is constructed;

    ii. Whether there exist distribution system-level solutions, or changes in operating procedures, or some combination, to eliminate the transmission station or substation from the CIP-014 List;

    iii. Whether the Proposed CMP requires new or expanded right-of-way;

iv. Whether the Proposed CMP will displace costs associated with maintaining physical security for stations/substations on the CIP-014 List; and

v. The estimated cost of the Proposed CMP.

6. PJM Interim/Periodic Review and Interim Consultation with State Commissions. Nothing in this Attachment M-4 precludes PJM, at its sole discretion, from conducting additional periodic examinations to verify the continuing validity of its findings and assessment under Step 4, above. Similarly, nothing in this Attachment M-4 precludes PJM from consulting with State Commissions in addition to those consultations specified in Step 5 above, with or without the participation of the relevant Transmission Owner.

7. Project Notification and Compliance.

   A. Transmission Owner Notification to PJM. Upon satisfaction of all parts of Step 5, the Transmission Owner shall notify PJM in writing that the Proposed CMP will be constructed and identify the location and specifications of the Proposed CMP selected. The Transmission Owner shall make a reasonable effort to seek alternative funding to offset project costs, including but not limited to U.S. Department of Energy grants associated with addressing national security, critical infrastructure or resilience.

   B. Compliance. The Transmission Owner will comply with all applicable licensing, permitting, siting, or certification requirements as well as all applicable proceedings for eminent domain authority.

8. CMP Construction. During construction of a CMP, the Transmission Owner carrying out such construction shall continue to take safeguards to ensure necessary confidentiality until the CMP is placed in service.

9. CMP In-Service Placement. A Transmission Owner shall have complied with all of its obligations set forth in the CMP Process Steps above before the CMP may be placed in-service.

10. Confidentiality. If at any step in the Attachment M-4 process, the level of needed confidentiality is eliminated with respect to elements of CMP information, such confidentiality shall be reduced or lifted. As a precondition to any Transmission Owner being eligible for recovery of the costs of the CMP, the Transmission Owner shall provide public notice of the existence of the CMP.

11. Public Review of CMP. At no time prior to the existence of the CMP being made known to the public by adherence to Step 10 of this Attachment M-4 shall the costs of any CMP be eligible for inclusion in rates filed by any Transmission Owner. After

notice of the existence of a CMP has been provided by adherence to Step 10 of this Attachment M-4, the Transmission Owner may propose to recover its investment in the CMP and the associated costs from Responsible Customers in its Zone through a rate, including a formula rate, in effect under the applicable Tariff, Attachment H similar to the cost recovery process it follows for other Supplemental Projects. Any such proposal shall be subject to discovery on all matters pursuant to the procedures applicable under the applicable Attachment H, the Federal Power Act, and the Commission's regulations, including any applicable procedures for the protection against disclosure of commercially sensitive information and Critical Energy Infrastructure Information.

c) **Modifications.** This Attachment M-4 may be modified under Section 205 of the Federal Power Act only if the proposed modification has been authorized by the PJM Transmission Owners Agreement-Administrative Committee in accordance with Section 8.5 of the Consolidated Transmission Owners Agreement ("CTOA").

d) **Sunset.** This Attachment M-4 terminates five years after the issuance date of an Order from the Federal Energy Regulatory Commission approving this Attachment M-4 for inclusion in the PJM Tariff; however, CMPs already under construction as of that date of termination may proceed and the conditions in Steps 8, 9, 10, and 11 shall remain in force. For any CMP construction occurring after the sunset date, quarterly status briefings shall be provided to any State Commission previously consulted under Step 5 until the CMP is placed in service pursuant to Step 9.