PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

Pauline Foley
Associate General Counsel
T: (610) 666-8248 | F: (610) 666-8211
pauline.foley@pjm.com

October 3, 2019

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

Re: PJM Interconnection, L.L.C., Docket No. ER20-34-000
Revisions to MISO-PJM Joint Operating Agreement to Enhance the Coordinated System Planning Process

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act[1] and Part 35 of the rules and regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[2] PJM Interconnection, L.L.C. ("PJM"), concurrently[3] with Midcontinent Independent System Operator, Inc. ("MISO") (collectively referred to herein as "RTOs"), submits for filing revisions to Article IX[4] of the Joint Operating Agreement between the Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C. ("MISO-PJM JOA" or "JOA").[5] These revisions

[1] 16 U.S.C. section 824d.

[2] 18 C.F.R. Part 35 (2019).

[3] Although the RTOs propose the identical amendments to the JOA, each RTO maintains its own version of the JOA in its own e-Tariff database at the Commission. Accordingly, each RTO must separately file the proposed amendments. As a result, the RTOs are submitting two filings concurrently to the Commission to implement the proposed amendments.

[4] Article IX of the MISO-PJM JOA governs Coordinated Regional Transmission Expansion Planning between MISO and PJM.

[5] The MISO-PJM JOA is a FERC-filed rate schedule of both PJM and MISO. The MISO-PJM JOA is designated as PJM's Rate Schedule No. 38 and is available on PJM's website at http://www.pjm.com/media/documents/merged-tariffs/miso-joa.pdf and MISO's Rate Schedule No. 5 and is available on MISO's website at https://www.misoenergy.org/Library/Pages?RateSchedules.aspx.

propose to further clarify the Coordinated System Plan ("CSP") process,[6] as well as to clean up inconsistencies overlooked in prior compliance filings.

One of the proposed revisions to the CSP study process, namely the language addressing joint studies,[7] is similar to a change accepted by the Commission relative to the MISO and Southwest Power Pool, Inc. ("SPP") Joint Operating Agreement ("MISO-SPP JOA"). Specifically, in that proceeding, the Commission accepted the removal of the requirement to develop a joint model under the MISO-SPP CSP study process.[8]

To that end, the RTOs propose to: (i) clarify that a CSP study that includes a more complex, longer duration study provides for, but does not require, the development of a joint model;[9] (ii) clarify that construction of Interregional Projects is subject to the regional tariff in which the facilities will be constructed;[10] (iii) revise the Interregional Market Efficiency Project ("IMEP") criteria to remove the requirement that at least one dispatchable generator in the adjacent market has a generation-to-load distribution factor ("GLDF") of five percent or greater;[11] (iv) remove references to use of a joint model from the determination of benefits for RTO's markets;[12] (v) remove the legacy provision that allows the RTOs to test any project against interregional cost

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[6] The MISO-PJM JOA CSP process includes a two-part coordinated system planning process. Specifically, the CSP provides for two types of studies: (i) a targeted study completed on a one-year calendar basis that focuses on particular areas, needs or potential expansions to ensure reliability coordination between the RTOs; and (ii) a more complex, two-year cycle study.

[7] JOA, section 9.3.7.2(a)(vii) *proposed*.

[8] *Midcontinent Sys. Operator, Inc., et al.*, 168 FERC ¶ 61,018 (July 16, 2019) ("July 16 MISO-SPP Order"). The formal name of the MISO-SPP JOA is the "Joint Operating Agreement between the Midcontinent Independent System Operator, Inc., and Southwest Power Pool, Inc." The MISO-SPP JOA is a FERC-filed rate schedule. The MISO-SPP JOA is designated as MISO's Rate Schedule No. 6 and is available on MISO's website at: https://www.misoenergy.org/legal/tariff.

[9] JOA, section 9.3.7.2(a)(vii) *proposed.*

[10] *Id.*, section 9.4.4.1 *proposed*.

[11] *Id.*, section 9.4.4.1.3(iii) *proposed*.

[12] *Id.*, section 9.4.4.1.3.1 *proposed*.

allocation criteria outside a CSP study;[13] and (vi) miscellaneous clean up revisions. These proposed JOA revisions reflect the result of the RTOs' stakeholder processes and are intended to improve and add greater clarity to development of the CSP process. PJM and MISO request an effective date of December 3, 2019, which is more than 60 days from the date of this filing.[14]

I. BACKGROUND

A. Revisions Made to the MISO/PJM JOA to Comply with Order No. 1000 and the Commission Orders Addressing the NIPSCO Complaint

Consistent with Order No. 1000, Interregional Projects are first identified in each RTO's regional processes before being submitted for consideration in the interregional processes.[15] As such, the Commission has required and accepted a number of revisions to the MISO-PJM JOA to make clear the importance of each RTO's regional needs.[16]

On September 11, 2013, following PJM's and MISO's Order No. 1000 compliance filings revising Article IX of the MISO-PJM JOA,[17] Northern Indiana Public Service Company ("NIPSCO") filed a complaint against MISO and PJM challenging their interregional transmission

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[13] *Id.*, section 9.4.4.3 *proposed*.

[14] The RTOs have collaborated in drafting their respective transmittal letters and submit (by separate filings being made contemporaneously) identical language to the MISO-PJM JOA regarding these revisions.

[15] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000 at P 397, FERC Stats. & Regs. ¶ 31,323 (2011) *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S. C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order No. 1000). Under Order No. 1000, the Commission left it to the transmission planning regions "adequate discretion to allow for the development and implementation of interregional transmission coordination procedures that suit the needs of the neighboring transmission planning regions . . . ." In addition, the Commission expressed hesitation to provide further guidance on how RTOs should develop and implement interregional transmission coordination procedures as such guidance could inadvertently impose restrictions that are not appropriate for a transmission planning region. *Id.*

[16] *Id.* at P 346.

[17] *PJM Interconnection, L.L.C.*, Order No. 1000 Interregional Compliance Filing, Docket No. ER13-1944-000 (July 10, 2013).

planning process and cost allocation methods in the JOA.[18] Specifically, NIPSCO requested the Commission order MISO and PJM to implement six reforms requiring revisions to the JOA to require: (i) the cross-border planning process run concurrently with the RTOs' regional transmission planning processes;[19] (ii) the RTOs develop and use a single combined model using the same assumptions;[20] (iii) the RTOs develop and jointly agree upon a single set of criteria for interregional economic transmission projects;[21] (iv) the RTOs amend the criteria for approval of IMEPs to address all benefits including avoidance of future market-to-market payments;[22] (v) the RTOs develop a process for joint planning and cost allocation of lower voltage and lower-cost transmission upgrades;[23] and (vi) improve JOA processes for generator interconnections and generator retirements.[24] Relevant to this filing, the April 21 NIPSCO Complaint Order granted

[18] *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, Complaint, Docket No. EL13-88-000 (Sept. 11, 2013) ("NIPSCO Complaint").

[19] The Commission granted the Complaint in part with regard to transmission planning cycles and directed the RTOs to revise the JOA to create deadlines in the JOA for each step in the CSP process and specify the maximum total amount of time the total CSP study process will take from the date the process begins to the date the CSP study is approved. *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, 155 FERC ¶ 61,058 at P 55 (Apr. 21, 2016) ("April 21 NIPSCO Complaint Order"); *see also N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, PJM Compliance Filing, Docket No. ER16-1967-000 at 4 - 5 (June 20, 2016) ("PJM Compliance Filing") and *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, MISO Compliance Filing, Docket No. ER16-1969-000 at 4 (June 20, 2016) ("MISO Compliance Filing") (together, "June 20 Compliance Filings").

[20] The Commission denied NIPSCO's Complaint regarding modeling and criteria. April 21 NIPSCO Complaint Order at P 88. The Commission found the JOA already requires annual exchange of data between the RTOs and a process to conduct the CSP study, including compromises on the assumptions and a joint model consistent with the models and assumptions used for each RTO's planning cycles. April 21 NIPSCO Complaint Order at PP 89, 90.

[21] *Id.*, n. 22.

[22] The Commission denied NIPSCO's request to require PJM and MISO to include avoidance of market-to-market payments as a separate discrete category of benefits for approval of an IMEP. *Id.* at P 151.

[23] The Commission granted in part and denied in part the Complaint and directed PJM and MISO to remove from the JOA the requirement to conduct a third, separate benefit-cost analysis for the combined MISO and PJM regions. *Id.* at P 129; *see also* PJM Compliance Filing at 5 - 6.

[24] The Commission denied NIPSCO's request to require the RTOs to use a joint model to study generator interconnection requests but directed PJM and MISO to submit revisions to the JOA to include the description of interconnection coordination procedures that are currently in the RTO's business practice manuals. April 21 NIPSCO Complaint Order at P 185. The Commission also directed PJM and MISO to propose revisions to the JOA that require the RTOs to coordinate their generator retirement studies. *Id.* at P 186.

NIPSCO's requested relief in part and required PJM and MISO to rely on their respective individual regional benefit calculations for benefit determination and interregional cost allocation. This eliminated the need for a separate benefit-to-cost analysis for IMEPs using a joint model with common assumptions for the combined PJM and MISO regions.[25]

On June 20, 2016, PJM and MISO submitted under separate cover their filing in compliance with the April 21 NIPSCO Complaint Order that, among other things, included revisions to the analysis of IMEPs to remove from the JOA the requirement to conduct a third, separate benefit-cost analysis for combined MISO and PJM regions.[26] The RTOs also removed from the JOA the requirement that an IMEP meet a separate benefit-cost analysis using a joint model in addition to each RTO's respective regional benefit metrics.[27]

B. Recent Commission Precedent on Removal of the Joint Model

Pursuant to the terms of the MISO-SPP JOA, the RTOs were required to develop a joint planning model for use in their CSP process. In their May 17 Filings, MISO and SPP included revisions to their CSP process to replace the use of a joint and common model with "appropriate respective regional models."[28] In support of their filing, MISO and SPP stated that both RTO staff and stakeholders devoted a great deal of time developing the joint modeling assumptions and how those assumptions differed from the assumptions being used in their respective regional models.

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[25] *See Id.* at P 129. PJM and MISO submitted additional revisions in a second compliance filing on April 24, 2017. *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, PJM 2nd Compliance Filing, Docket No. ER16-1967-002 (Apr. 24, 2017) ("PJM 2nd Compliance Filing") and *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, MISO Additional Compliance Filing, Docket No. ER16-1969-003 (Apr. 24, 2017) and *Errata Filing* (Apr. 25, 2017) ("MISO 2nd Compliance Filing").

[26] PJM Compliance Filing at 6 and MISO Compliance Filing at 5 - 6.

[27] *Id.*

[28] May 17 Filing Letter at 9 (proposing revisions to MISO-SPP JOA, section 9.3.3.2).

[29] Additionally, the RTOs explained that there were inherently different results between the joint model and the RTOs' respective regional models. Thus, requiring a joint model to evaluate potential interregional projects using a different set of assumptions than those used by each RTO in their respective regional models was not informative to the planning process. The RTOs explained that replacing the use of a joint and common model with regional models was more in keeping with the MISO-PJM annual CSP study process, which uses each RTO's regional models.[30]

On July 16, 2019, the Commission issued an Order accepting the RTOs' proposed revisions to the MISO-SPP JOA.[31] In the July 16 MISO/SPP Order, the Commission found that eliminating the use of a joint model in their evaluation of interregional transmission projects is just and reasonable and consistent with the Commission's requirements in Order No. 1000.[32] Specifically, the Commission stated that:

> Order No. 1000's interregional transmission coordination requirements do not require that transmission planning region pairs create a joint interregional model to evaluate the potential for more efficient or cost-effective solutions to interregional transmission needs, but, rather, require only that the public utility transmission providers within a region must, as a group, establish further procedures with the transmission providers in each of its neighboring transmission planning regions for the purpose of: (1) coordinating and sharing the results of the respective regional transmission plans to identify possible interregional transmission facilities that could address regional transmission needs more efficiently or cost-effectively than separate regional transmission facilities; and (2) jointly evaluating those interregional transmission facilities that the pair of neighboring transmission planning regions identify, including those proposed by transmission developers and stakeholders.**[33]**

[29] For example, the RTOs had to decide whether to use MISO's assumption, SPP's assumption or a new negotiated assumption. *See* May 17 Filing Letter at 5.

[30] *See* May 17 Filing Letter at 5. *See also* MISO-PJM JOA, section 9.3.7.2(a)(i).

[31] *Midcontinent Indep, Sys. Operator, Inc., et al.,* 168 FERC ¶61,018 (2019) ("July 16 MISO/SPP Order").

[32] *Id.* at P 41.

[33] *Id.* (*citing* Order No. 1000, 136 FERC ¶ 61,051 at P 399); Order No 1000-A, 139 FERC ¶ 61,132 at P 493 (*citing* Order No. 1000, 136 FERC ¶ 61,051 at P 396); *Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,045, at P 180 (2015).

The Commission also noted that MISO and SPP would consider interregional transmission projects through their respective regional transmission planning processes and continue to jointly evaluate interregional transmission facilities through the Joint Planning Committee, Interregional Planning Stakeholder Advisory Committee, and CSP study process. Given those factors, the Commission found that MISO and SPP would continue to meet the requirements of Order No. 1000 even after the elimination of the joint model.[34]

C. Lessons Learned following Implementation of Order No. 1000 and the NIPSCO Complaint Orders

In implementing the JOA changes, the PJM and MISO have found that other provisions should be revised to: (i) conform to changes made as a result of the April 21 NIPSCO Complaint Order; (ii) eliminate language that is inconsistent with the RTOs' prior filings submitted in compliance with Commission orders issued in Docket No. EL13-88; and (iii) further improve the CSP process. The revisions proposed herein also will help clarify the alignment between the JOA CSP process and each RTO's regional transmission planning processes. Importantly, these revisions are not intended to change the CSP study process.

D. Stakeholder Process

Late in 2017, PJM and MISO started working with stakeholders through the Interregional Planning Stakeholder Advisory Committee ("MISO-PJM IPSAC") to examine whether, based on experience with the Order No. 1000 interregional planning process, additional changes could be

[34] *Id.*

made to improve the process.[35] After soliciting feedback,[36] PJM and MISO discussed potential revisions to the JOA with stakeholders and formalized proposals for those revisions that had broad support among the RTOs and their stakeholders.[37] PJM and MISO finalized the proposed JOA revisions in early 2019 and presented to stakeholders for review and feedback in both regional[38] and interregional[39] forums.

II. DESCRIPTION OF PROPOSED REVISIONS

PJM and MISO propose to modify the MISO-PJM JOA, sections 9.3 and 9.4.

A. Revisions to Sections 9.3 and 9.4 to Clarify that the RTOs May Develop a Joint Model for More Complex, Longer Duration CSP Studies, As Appropriate.

Under section 9.3.7.2(a), which details the coordination of studies required for the development of the CSP, subsection 9.3.7.2(a)(vii)[40] was added to comply with the April 21 NIPSCO Complaint Order and states that a CSP Study "may include more complex, longer duration studies involving joint model development . . . ."[41] While such language could be read to mean that a joint model will be developed for more complex, longer duration studies, such interpretation was not intended. Rather, as indicated in a footnote to the June 20 Filing, the "two-

[35] *See* MISO-PJM IPSAC Presentation at https://pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx.

[36] *See* MISO-PJM IPSAC Presentation at https://pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180330/20180330-ipsac-presentation.ashx.

[37] *See* MISO-PJM IPSAC Presentation at https://pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180511/20180511-ipsac-presentation.ashx, https://pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180801/20180801-ipsac-presentation-rev-4.ashx.

[38] *See* PJM Planning Committee https://pjm.com/-/media/committees-groups/committees/pc/20190516/20190516-item-14a-pjm-miso-joa-revisions.ashx.

[39] *See* MISO-PJM IPSAC Presentation at https://pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190419/20190419-ipsac-presentation.ashx.

[40] In the June 20 Compliance Filing, MISO-PJM JOA, section 9.3.7.2(a)(vii) was section 9.3.6(a)(vii).

[41] MISO-PJM JOA, section 9.3.7.2(a)(vii).

year cycle study will include a more complex scope that *may* involve joint model development (emphasis added) . . . ."[42] To clarify that a joint model may be developed for a more complex, longer duration study, the RTOs propose to revise subsection 9.3.7.2(a)(vii) as follows:

> (vii) A Coordinated System Plan study may include more complex, longer duration studies ~~involving joint model~~ <u>that may involve</u> development <u>of a joint model, as appropriate,</u> ~~that~~ <u>to</u> address~~es~~ reliability, market efficiency or public policy needs. Such studies will be conducted on a two-year cycle commencing in the third quarter of the first year of the two-year cycle, if the need is determined by the JRPC. A Coordinated System Plan study scheduled on a two-year cycle will conclude no later than the end of the second year of the two-year cycle.

This revision is necessary as a joint model is not needed for all complex, longer duration studies. Developing a joint model for complex, longer duration studies requires PJM and MISO staff to dedicate a great deal of time determining the joint modeling assumptions and how those differ from the assumptions being used in PJM's and MISO's regional models. For example, similar to the MISO and SPP arguments raised in their May 17 Filings, PJM and MISO staff must decide whether to use PJM's assumption, MISO's assumption, or a new negotiated assumption. This complication, and the need to be transparent with stakeholders about the decisions being made, leads to complexity and necessitates a large time commitment in order to build a joint model.

Additionally, there are inherently different results between the joint model and the RTOs' respective regional models. Thus, using a joint model to evaluate potential interregional projects using a different set of assumptions than those used by each RTO in their respective regional models is not informative to the planning process. This problem is amplified by the CSP process which requires projects be studied using both a joint model for complex, longer duration studies and each RTO's respective regional models. This modeling issue is one of the reasons why

[42] PJM Compliance Filing at P. 3, n. 9.

projects initially identified as mutually beneficial to the RTOs based on analysis using a joint model ultimately fail to show sufficient mutual benefit under the RTOs' regional review processes.

In addition, the reasons to develop a joint model have been removed from the JOA. Specifically, in compliance with the April 21 NIPSCO Complaint Order,[43] PJM and MISO removed the requirement that PJM and MISO conduct a third, separate benefit-cost analysis for the combined MISO and PJM regions using a joint model.[44] Accordingly, PJM and MISO revised the JOA at sections 9.4.4.1.2, 9.4.4.1.2.1 and 9.4.4.2.2[45] to remove the references to the separate benefit-cost analysis using a joint model for the combined MISO and PJM region.[46] Thus, based on the June 20 Compliance Filings, the RTOs no longer use a combined joint model to determine benefits or costs for IMEPs, nor is a combined joint model used for Interregional Reliability Projects.[47]

PJM and MISO propose that in those instances where there is no use for a combined joint model in the JOA evaluation or approval processes, the RTOs should not be required to develop a joint model for the combined regions under section 9.3.7.2(a)(vii). Accordingly, PJM and MISO propose to revise section 9.3.7.2(a)(vii) to allow for the development of a joint model, as appropriate. Since MISO and PJM will consider Interregional Projects through their respective regional transmission planning processes and will continue to jointly evaluate Interregional

[43] April 21 NIPSCO Complaint Order at P 129.

[44] PJM Compliance Filing at 6.

[45] *Id.* at 5 – 7.

[46] *Id.*

[47] A joint model is developed for Cross Border Baseline Reliability Projects (for load flow) and for Targeted Market Efficiency Projects. Neither project type qualifies under a longer, more complex study.

Projects through the Joint RTO Planning Committee,[48] IPSAC[49] and CSP study processes,[50] interregional planning between the two RTOs will continue to meet the requirements of Order No. 1000.[51]

Consistent with this revision, PJM and MISO also propose changes to: (i) section 9.3.7.2(b)(vi) to ensure consistency with the changes to section 9.3.7.2(a)(vii); and (ii) section 9.4.4.1.3.1 to conform to changes made to this section in the June 20 Compliance Filing,[52] and accepted by the Commission in the January 19, 2017 Order, to remove from the JOA the requirement that an IMEP meet a benefit-to-cost ratio for the combined MISO-PJM regions.[53]

B. Clarification to Criteria for an Interregional Project

Under Order No. 1000, the Commission determined that a facility located solely within one region must allocate costs solely within that transmission planning region unless the adjacent region voluntarily agrees to assume a portion of those costs. However, the Commission determined that this principle did not apply to the cross-border cost allocation methods developed by PJM and MISO and memorialized in their JOA due to their intertwined configuration.[54] As a result, PJM's and MISO's obligations are unique as compared to other regions.

Given such precedent, PJM and MISO propose to further clarify which tariff applies under this scenario by modifying section 9.4.4.1 to state that, even if a project is located solely within

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[48] MISO-PJM JOA at section 9.1.1.1.

[49] *Id.*, at section 9.1.2

[50] *Id.*, at section 9.3.

[51] *Midcontinent Indep. Sys. Operator, Inc., et al.*, 168 FERC ¶61,018 at P 41 (July 16, 2019).

[52] In the PJM Compliance Filing, this section was referred to as section 9.4.4.1.2.1.

[53] *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, 158 FERC ¶ 61,049 (Jan. 19, 2017) ("January 19 Order").

[54] Order No. 1000 at P 586(4), n. 455.

one region but is paid for and benefiting the adjacent region only, the project must comply with the tariff of the region in which the transmission facility will be located. In addition, the revisions also clarify that the criteria for interregional projects such as Cross-Border Baseline Reliability Projects (section 9.4.4.1.1), Interregional Reliability Projects (section 9.4.4.1.2) or IMEPs (section 9.4.4.1.3) must also be satisfied.[55] PJM and MISO propose to further clarify that an Interregional Project will be constructed under the tariff of the region in which the facility will be located regardless of who bears the cost of such project.[56]

The RTOs believe this clarification is appropriate as it is specific to PJM's and MISO's JOA requirements under Order No. 1000. Additionally, this clarification will eliminate any confusion as to which tariff applies regardless of who pays for or is responsible for construction of an Interregional Project. Finally, this revision is consistent with the way in which affected system upgrades are handled under the JOA interconnection process. Specifically, under the JOA procedures relative to generation interconnection requests with affected system upgrades, the interconnection customer is required to enter into study agreements under the affected system's tariff[57] and construct such affected system network upgrades under the terms of the regional tariff in which the affected system network upgrades will be constructed.[58]

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[55] JOA, section 9.4.4.1 *proposed.*

[56] This is similar to the requirement under the MISO -SPP JOA where an Interregional Project is subject to the applicable OATT. *See* MISO Rate Schedule 6 at Section 9.7.1.

[57] JOA, section 9.3.3(j).

[58] *Id.*, section 9.3.3(m).

C. Revision to IMEP Criteria to Eliminate the Use of a Third Measure under the JOA

Under the current JOA, an IMEP must meet three criteria. Specifically, section 9.4.4.1.3 provides that an IMEP must (i) be evaluated as part of a CSP or joint study process, (ii) qualify as an economic transmission project under the PJM regional transmission expansion plan and a market efficiency project or multi-value project that meets multi-value project criteria 2 or 3 under Attachment FF of the MISO OATT; and (iii) address one or more constraints for which at least one dispatchable generator in the adjacent market has a generator to load distribution factor ("GLDF") of five percent or greater as determined using the CSP power flow model. The RTOs propose to remove this third criterion as an unnecessary hurdle to the development of an Interregional Project.

While this third criterion made sense when the RTOs were required to develop a joint economic model and the joint model was used to evaluate benefits and interregional cost allocation for IMEPs, that is no longer the case as a result of the June 20 Compliance Filing. As noted above and as directed by the April 21 NIPSCO Complaint Order, the RTOs removed the requirement that PJM and MISO conduct a third, separate benefit-cost analysis for the combined MISO and PJM regions for IMEPs. Instead, the RTOs use the regional cost-benefit analyses under their respective tariffs. Since such constraints are addressed under each RTO's regional processes,[59] PJM and MISO propose to remove this third criterion to consider only projects addressing one or more constraints with 5% or greater GLDF determined using a combined CSP power flow model and rely upon each RTO's respective regional requirements. This change is reasonable as PJM and

[59] *See* PJM Manual 14F: Competitive Planning Process, section 82.1.1 (Eligible Congestion Drivers), which details how PJM identifies eligible congestion drivers for which market efficiency projects are being solicited under its open proposal windows.

MISO have found that this additional criterion may actually hinder the RTOs' ability to select an Interregional Project found to be beneficial to both regions at the regional level.

D. Revisions to the Exchange of Information Used to Determine the Need for a CSP Study

Under the development of the CSP, PJM and MISO propose to revise section 9.3.7.2(a)(ii) to clarify that in addition to exchanging information related to interconnection requests, the RTOs will also exchange long-term firm transmission service requests located near the seam or expected to impact the adjacent region.[60] This reference to long-term firm transmission service should be added to link the development of the CSP with section 9.3.4, the JOA section that describes the process for analyzing long-term firm transmission service requests. MISO and PJM also propose to include references in section 9.3.7.2(a)(ii) to the sections of the JOA that detail the processes for the exchange of such information.[61]

E. Proposal to Eliminate the Determination of Interregional Cost Allocation Share Outside the CSP

There remains in the JOA a legacy provision that allows either RTO to request that a project be tested against the interregional cost allocation criteria during interim periods between periodic formal releases of the CSP.[62] Prior to Order No. 1000 and the NIPSCO Complaint, there was little detail or structure around the CSP study process.

As a result of the NIPSCO Complaint, the Commission found that the existing open-ended CSP process in the JOA did not establish timely, specific deadlines for the CSP study. In the April 21 NIPSCO Complaint Order the Commission directed PJM and MISO clarify how the CSP

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[60] MISO-PJM JOA, section 9.3.7.2(a)(ii) *proposed.*

[61] *Id.*

[62] JOA, section 9.4.4.3.

study interacted and aligned with each RTO's regional planning processes. As a result, the RTOs submitted a compliance filing adding more detail around the CSP process. More specifically, the RTOs proposed revisions detailing that a targeted study will be conducted on a one-year calendar basis and a more complex two-year cycle study will be conducted on a two-year calendar basis including specific deadlines and timeframes under which the study process will be conducted.[63] Further detail and clarification to the CSP study process was added in a subsequent compliance filing as well.[64] As a result of the structured timeframes around the CSP study process, the RTOs have found that section 9.4.4.3 is no longer needed, as studies are performed on a regular basis. In fact, given the relationship between the JOA and each RTO's regional processes, it is not clear that any time could be saved using this process. Rather, it could be potentially disruptive to the CSP study process. Accordingly, the RTOs propose to delete such provision in order to focus on meeting the CSP study deadlines and timeframes detailed in the JOA.

*F. Ministerial Revision*s

The RTOs propose to revise section 9.4.4.1.3.1(b) to clarify that annual revenue requirements are determined based on installed costs and fixed charge rate applicable under each RTO's regional process.

In addition to the substantive additions to the MISO-PJM JOA noted above, the RTOs also submit minor, non-substantive revisions to renumber sections 9.4.4.4, 9.4.4.5 and 9.4.4.6 to 9.4.4.3, 9.4.4.4 and 9.4.4.5, respectively as a result of deleting section 9.4.4.3.

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[63] PJM Compliance Filing at 4 – 5.

[64] *See supra,* at 4, n. 21.

III. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to, and the parties request the Secretary to include on the official service list, the following:

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
Ph: (202) 423-4743
craig.glazer@pjm.com

Pauline Foley
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
Ph: (610) 666-8248
pauline.foley@pjm.com

IV. CONTENTS OF THIS FILING

The following is a list of documents submitted with this filing:

1. This transmittal letter;

2. Attachment A – Revised JOA effective December 3, 2019, which date is more than 60 days from the date of this filing (in redlined form); and

3. Attachment B – Revised JOA effective December 3, 2019, which date is more than 60 days from the date of this filing (in clean form).

V. EFFECTIVE DATE

PJM and MISO request an effective date of December 3, 2019, which is more than 60 days after the date of this filing for the proposed modifications to the MISO-PJM JOA, Article 9, sections 9.3 and 9.4.

VI. NOTICE AND SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[65] PJM will post a copy of this filing to the FERC filings section of its

[65] *See* 18C.F.R sections 35.2(e) and 385.2010(f)(3) (2019).

internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[66] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

VII. CONCLUSION

PJM and MISO respectfully request that the Commission accept the proposed revisions to the JOA to further clarify the Coordinated System Plan ("CSP") process, as well as to clean up inconsistencies overlooked in prior compliance filings.

Respectfully submitted,

By: ______________________

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
Ph: (202) 423-4743
Fax: (202) 393-7741
craig.glazer@pjm.com

Pauline Foley
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
Ph: (610) 666-8248
Fax: (610) 666-8211
pauline.foley@pjm.com

On behalf of PJM Interconnection, L.L.C.

Dated: October 3, 2019

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

Attachment A

Revisions to the PJM-MISO Joint Operating Agreement

(Marked / Redline Format)

9.3 Coordinated System Planning.

The primary purpose of coordinated transmission planning and development of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, enhance the competitiveness of electricity markets, or promote public policy. The Parties will conduct such coordinated planning as set forth in this Section 9.3 and subsections thereof.

9.3.1 <u>Single Party Planning</u>.

Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of the Party, NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents its annual regional plan prepared according to the procedures, methodologies, and business rules documented by the region. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party's OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties' respective systems.

9.3.2 <u>Coordinated System Plan</u>.

The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.7. The Coordinated System Plan shall also include the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses.

9.3.3 Analysis of Interconnection Requests.

In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. The process for coordination of interconnection studies and Network Upgrades is detailed below:

(a) Consistent with the data exchange provisions of the manuals, the Parties will exchange current power flow modeling data annually and as necessary for the study and coordination of interconnection requests. This will include the associated update of the other Party's relevant queue requests, contingency elements, monitoring elements data, and other data as may be required.

(b) The coordinated interconnection studies will determine the potential impact on the direct connect system and on the impacted Party. The direct connect system will be responsible for communicating coordinated interconnection study results to the direct connect interconnection customer.

(c) The Parties will coordinate and mutually agree on the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party.

(i) The transmission reinforcement and the study criteria used in the coordinated interconnection studies will conform to and incorporate provisions as outlined in the PJM and MISO Business Practices Manuals and the Parties' respective Tariffs.

(ii) The PJM and PJM transmission owner study and reinforcement criteria will apply to studies performed to determine impacts on the PJM transmission system when PJM evaluates the impact of MISO generation on PJM transmission facilities.

(iii) The MISO and MISO transmission owner study and reinforcement criteria will apply to studies performed to determine impacts on the MISO transmission system when MISO evaluates the impact of PJM generation on MISO transmission facilities.

(iv) The identification of all impacts on the Parties' transmission systems shall include a description of the required system reinforcement(s), an estimated planning level cost and construction schedule estimates of the system reinforcements.

(v) If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

The Parties will strive to minimize the costs associated with the coordinated study process.

(d) During the course of its interconnection studies, PJM shall monitor the MISO transmission system and provide to MISO the draft results of the potential impacts to the MISO transmission system. These potential impacts shall be included in the PJM System Impact Study report along with any information regarding the validity of these impacts and any transmission system reinforcements received from MISO and the MISO transmission owners.

(e) Following issuance of the PJM Feasibility Study report and after the Interconnection Customer executes the PJM System Impact Study Agreement, PJM shall forward to MISO, at a minimum of twice per year (April 15 and October 15), information necessary for MISO and the MISO transmission owners to study the impact of the PJM Interconnection Request(s) on the MISO transmission system. MISO and the MISO transmission owners shall study the impact(s) of the PJM Interconnection Request(s) on the MISO transmission system and provide draft results to PJM by:

(i) March 1 for PJM Interconnection Request(s) provided to MISO on or before October 15 of the previous year; and

(ii) September 1 for PJM Interconnection Request(s) provided to MISO on or before April 15 of the same year.

(f) During the determination of reinforcements for an Interconnection Request that are required to mitigate MISO constraint(s), PJM and MISO may identify other planned non-MISO reinforcement(s) that may alleviate such constraint(s) inside the MISO region. Under such circumstances, any PJM interconnection project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are placed into service. MISO shall determine the necessary injection limits associated with the PJM Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through MISO’s affected system analysis are in service.

(g) During the course of MISO’s interconnection studies, MISO shall monitor the PJM transmission system and provide to PJM the draft results of the potential impacts to the PJM transmission system. Those potential impacts shall be included in the MISO System Impact Study report along with any information regarding the validity of these impacts and possible mitigation received from PJM and the PJM transmission owners.

(h) Prior to commencing the MISO Definitive Planning Phase (“DPP”) study, MISO shall forward to PJM, at a minimum of twice per year (January 1 and July 1), information necessary for PJM and the PJM transmission owners to study the impact of the MISO Interconnection Request(s) on the PJM transmission system. For the prescribed times when MISO provides this information to PJM, January 1 and July 1, PJM and the PJM transmission owners shall study the impact of the MISO Interconnection Request(s) on the PJM transmission system and provide the draft results to MISO by:

(i) March 31 for requests submitted to PJM on or before January 7 of the same year; and

(ii) September 29 for requests submitted to PJM on or before July 7 of the same year.

(i) During the determination of reinforcements for an Interconnection Request that are required to mitigate PJM constraint(s), PJM and MISO may identify other planned non-PJM reinforcement(s) that may alleviate a constraint inside the PJM region. Under such circumstances, any MISO interconnection project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are placed into service. PJM shall determine the necessary injection limits associated with the MISO Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through PJM's affected system analysis are in-service.

(j) If the coordinated interconnection study identifies constraints that require infrastructure additions on the impacted system to mitigate them, then the potentially impacted Party may perform its own analysis, in conjunction with the direct connect Party's Interconnection Studies. The interconnection customer whose project requires mitigation of constraint(s) found on an impacted Party's system shall enter into the appropriate Facilities Study agreement as required under the impacted Party's OATT.

(k) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(l) If the results of the coordinated study process indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the appropriate study report prepared for the interconnection customer.

(m) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(n) The Interconnection Customer whose project requires mitigation of constraint(s) found on an impacted Party's system shall enter into the appropriate Facilities Study Agreement as required under the impacted Party's Tariff.

(o) In the event that Network Upgrades are required on the potentially impacted Party's system, then interconnection service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(p) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. These lists will be presented annually to the IPSAC.

9.3.4 <u>Analysis of Long-Term Firm Transmission Service Requests</u>.
In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party's business practices manuals that are publicly available on each Party's website. Both Parties' manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon the posting to the OASIS of a request for service, the Party receiving the request will coordinate the study of the request, pursuant to each Party's business practices manuals, which will determine the potential impact on each Party's system. The Party receiving the request will be responsible for communicating coordinated study results to the customer requesting such service.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party's OASIS is unnecessary (i.e., the potentially impacted Party is "off the path"), then the potentially impacted Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process. The JRPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) If constraints are identified during the coordinated study on the impacted system, then the potentially impacted Party may perform its own analysis in conjunction with the studies performed by the Party that has received the request for service. The customer whose request for service requires mitigation of constraint(s) found on an impacted Party's system shall enter into the appropriate facilities study agreement as required under the impacted Party's OATT. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request's Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the Party receiving the request will identify the need for such Network Upgrades in the system impact study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party's system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

9.3.5 Analysis of Incremental Auction Revenue Rights Requests.

The Parties will coordinate, as deemed appropriate,[1] the conduct of any studies in response to a request for Incremental Auction Revenue Rights ("Incremental ARRs") ("Incremental ARR Request") made under one Party's tariff to determine its impact on the other Party's system. Results of such coordinated studies will be included in the impacts reported to the customer requesting Incremental ARRs as appropriate. Coordination of studies and Network Upgrades will include the following:

(a) The Parties will coordinate the base Firm Flow Entitlement values associated with the Coordinated Flowgates that may be impacted by the Incremental ARR Request.

(b) Upon receipt of an Incremental ARR Request or the review of studies related to the evaluation of such request, the Party receiving the Incremental ARR Request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the Incremental ARR Request will notify the other Party and convey the information provided in the request in addition to but not limited to the list of impacted constrained facilities.

(c) During the System Impact Study, the potentially impacted Party may participate in the coordinated study by providing input to the studies to be performed by the Party receiving the Incremental ARR Request. The potentially impacted Party shall determine the Network Upgrades, if any, needed to mitigate constraints on identified impacted facilities. The Parties shall coordinate to ensure any proposed Network Upgrades maintain the reliability of each Party's transmission system.

(d) Any coordinated System Impact Studies will be performed in accordance with the mutually agreed upon study timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement in accordance with applicable tariff provisions.

(e) During the Facilities Study, the potentially impacted Party may conduct its own Facilities Study as a part of Facilities Study being conducted by the Party that received the Incremental ARR request. The study cost estimates indicated in the Facility Study Agreement between the Party receiving the request and the Incremental ARR customer will reflect the costs and the associated roles of the study participants, including the potentially impacted Party. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the Incremental ARR Request shall collect from the Incremental ARR customer, and forward to the potentially impacted Party, the agreed upon payments associated with the performance of such studies.

(g) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted Party, the Party receiving the request will identify the need for such Network Upgrades in the System Impact Study prepared for the Incremental ARR customer.

(h) The construction of such Network Upgrades will be subject to the terms of the potentially impacted Party's tariff, the agreement among owners transferring functional control of transmission facilities to the control of the potentially impacted Party, and applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party's system, the Incremental ARR will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

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[1] Infra (b).

9.3.6 Analysis of Generator Deactivations (retirements and suspensions).

(a) The Party ("Noticed Party") receiving a new request from a generation owner to retire, deactivate, or mothball (or suspend operations as defined under the MISO Tariff) its generation unit will notify the other Party of such deactivation request no later than five (5) business days after receipt of the notice by the Noticed Party. The other Party ("Other Party") will determine if any study is required to evaluate potential impacts to its system due to the proposed generator deactivation in the Noticed Party's system. Any studies required due to a notice to deactivate (retire or suspend operations as defined under the MISO Tariff) will be performed under each Party's respective Tariff. Each Party's regional study results will be documented and provided to the other Party for informational purposes only.

(b) Both Parties will share all information necessary to evaluate potential impacts to their respective systems due to the notice. Such coordination shall provide for:

(i) Exchange of current power flow modeling data as necessary for the study and coordination of generator deactivations (retirements and suspensions). This will include the associated update of the other Party's generator availability, contingency elements, monitoring elements data, and other data as may be required.

(ii) Coordination by the Parties to align the assumptions of any analyses during development of the scope of any required studies. The scope design will include, as appropriate, evaluation of the transmission system against the criteria applicable to each Party for such studies.

(c) Following the exchange of information pursuant to section 9.3.6(b), the Other Party will conduct screening and evaluation of projects needed to mitigate identified impacts on its system. The Other Party will use reasonable efforts to perform an initial assessment and provide an indication of the impacts on its system to the Noticed Party within 65 days of receipt of the notice from the Noticed Party. The Other Party will provide a list of potential system reinforcements required on its system and estimated time for completion of those system reinforcements to the Noticed Party as soon as they are available.

(d) Each Party will be responsible for any regional Network Upgrades or other mitigation required on their respective system as a result of a request to deactivate (retirement or suspension).

(e) Any impact(s) on the Other Party's system identified in the analysis will not be used to determine the need to retain the generator requesting to deactivate.

(f) The identification of Network Upgrades required for generator deactivation (retirement or suspension) in the Other Party's system may require coordination through the JRPC. The Parties will endeavor to make such information available to the JRPC in a timely manner following publication of information through the Parties' regional processes. Additional coordination, as may be needed, will be conducted pursuant to the Coordinated System Plan study process as mutually agreed to be the Parties in accordance with the provisions of Section 9.3.7.

(i) The JRPC will incorporate any needed regional upgrades that may be identified by the generator deactivation studies coordinated pursuant to this section 9.3.6 into the annual review processes of Section 9.3.7 for the purpose of determining if there is a more efficient or cost effective Interregional Reliability Project that may replace one or more of the identified regional Network Upgrades required for the generator deactivation.

(ii) The JRPC will consider the results of the deactivation analyses forwarded to the committee at the next scheduled JRPC meeting or within 30 days of receipt of the completed study information from both Parties. Depending on the timing of the receipt of the study information, the JRPC will determine the most appropriate process for including the regional deactivation results into the development of the Coordinated System Plan. Such process will include IPSAC review according to the Coordinated System Plan process of Section 9.3.7.

Throughout the interregional review process any confidentiality provisions of the Parties Tariff's will be respected. Critical identified Interregional Reliability Projects for which the need to begin development is urgent will be presented to the Parties' Boards for approval as soon as possible after identification through the Coordinated System Plan study process. Other identified Interregional Reliability Projects presented to the Parties' Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade.

9.3.7 **<u>Development of the Coordinated System Plan</u>.**

9.3.7.1

Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties' systems. Each Party's annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Section, to obtain financial compensation due to the impact of another Party's plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:

(a) Integrate the Parties' respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation, market participant funded, or merchant transmission projects) and Network Upgrades identified jointly by the Parties, together with alternatives to Network Upgrades that were considered;

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to the integration described in the preceding part (a); and

(c) Describe results of the joint transmission analysis for the combined transmission systems, as well as explanations, as may be necessary, of the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

9.3.7.2

Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for a Coordinated System Plan study described in Section 9.3.7.2.a; and 2) Coordinated System Plan study described in Section 9.3.7.2.b.

(a) Determine the Need for a Coordinated System Plan Study.

(i) On an annual basis, beginning in the fourth quarter of each calendar year and continuing through the first quarter of the following calendar year, the Parties shall perform an annual evaluation of transmission issues identified by each Party including issues from the respective Party's market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed to schedule taking into consideration each Party's regional planning cycles.

(ii) The JRPC's annual review of transmission issues shall include the following steps:

a. Exchange of the following information during the fourth quarter of each calendar year or as specified below:

   i. Regional issues and newly approved regional projects located near the interface or expected to impact the adjacent region;

   ii. Newly identified regional transmission issues for which there is no proposed solution;

   iii. Interconnection and long-term firm transmission service requests under coordination by the Parties located near the interface or expected to impact the adjacent region will be exchanged pursuant to sections 9.3.3 and 9.3.4, respectively;

   iv. Market-to-market historical flowgate congestion between the Parties.

b. Joint review by the Parties of regional issues and solutions in January of each calendar year;

c. Receipt of Third Party issues in the first quarter of each calendar year;

d. Review of regional issues with input from stakeholders at the IPSAC meeting conducted during the first quarter of each calendar year; and

e. Decision by the JRPC on whether or not to conduct a Coordinated System Plan study.

(iii) The JRPC through each Party's respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to be held in the first quarter of each year to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting for consideration by the IPSAC and JRPC.

(iv) Within 45 days following the annual issues evaluation meeting with IPSAC in the first quarter of the calendar year, the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (1) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (2) if after two consecutive years in which a Coordinated System Plan study has not been performed, and one Party votes in favor of performing a Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study within five business days of the JRPC's decision.

(v) When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study and identify whether it is a targeted study as defined in this Section at (vi) or a more complex, two-year cycle study as defined in this Section at (vii).

(vi) If a Coordinated System Plan study includes targeted studies of particular areas, needs or potential expansions to ensure that the coordination of the reliability and efficiency of the Parties' transmission systems, then such targeted studies will be conducted during the first half of the calendar year. In years when the Coordinated System Plan study includes only targeted studies as defined herein, they may be conducted at any time during the calendar year but shall be completed within the calendar year in which they are identified.

(vii) A Coordinated System Plan study may include more complex, longer duration studies that may involve ~~involving joint model~~ development ~~that~~ of a joint model, as appropriate, to address~~es~~ reliability, market efficiency or public policy needs. Such studies will be conducted on a two-year cycle commencing in the third quarter of the first year of the two-year cycle, if the need is determined by the JRPC. A Coordinated System Plan study scheduled on a two-year cycle will conclude no later than the end of the second year of the two-year cycle.

a. For a Coordinated System Plan study scheduled on a two-year cycle, the JRPC will provide notice to the IPSAC in the fourth quarter of the year preceding commencement of the two-year study cycle.

b. The first year of the two-year study cycle will consist of model preparation and issue identification and be timed in accordance with each RTO's regional planning processes for model preparation and issue identification. Two-year study cycle activities and their interaction with regional activities are further described in the applicable sections of 9.3.7, particularly in section 9.3.7.2(b)(vii).

(viii) When a Coordinated System Plan study is determined to be necessary by the JRPC, the specific study process steps will depend on the type and scope of the study. The JRPC shall provide a schedule and binding deadlines for each step in the Coordinated System Plan study process no later than 15 days after the IPSAC meeting provided for in Section 9.3.7.2(b)(ii) following the JRPC's decision to initiate such study.

(b) Coordinated System Plan Study Process

(i) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(ii) The JRPC will develop a scope and procedure for the coordinated planning analysis. The scope of the studies will include evaluations of issues resulting from the annual coordinated review and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment at an IPSAC meeting scheduled no later than 30 days after the decision to conduct a Coordinated System Plan study.

(iii) Ad hoc study groups may be formed as needed to address localized seams issues or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented. Targeted studies will utilize the best available regional models for transmission and market efficiency analysis.

(iv) The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party's criteria. Stakeholder input will be solicited for potential remedies to identified issues, which includes stakeholder and transmission developer proposals for Interregional Projects. The study scope developed under Section 9.3.7.2(b)(ii) will include the schedule for acceptance of such stakeholder Interregional Project proposals including supporting analyses that address issues identified in the JRPC solicitation.

(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation of the transmission system against the reliability criteria, operational performance criteria, economic performance criteria, and public policy needs applicable to each Party.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. If ~~T~~the JRPC ~~will~~ develops joint study models, the JRPC will do so consistent with the models and assumptions used for the regional planning cycle most recently completed, or underway, as appropriate. If the Coordinated System Plan study requires transmission evaluations driven by different regional needs (for example transmission that addresses any combination of needs including regional reliability, economics and public policy), then the coordination of studies, models, and assumptions will include the analyses appropriate to each region. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be accommodated. Known updates and revisions to models will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback to the JRPC regarding the study models.

(vii) When Coordinated System Plan studies are undertaken pursuant to a two-year study cycle defined in this Section at (a)(vii), the following schedule will be followed unless otherwise mutually agreed to by the Parties.

a. Parties will provide updated identification of regional issues identified in this Section at (a) by January of the second year of the two-year cycle.

   i. If MISO conducts a regional Market Congestion Planning Study as part of the MTEP, MISO will use that Market Congestion Planning Study to identify the MISO regional issues that will be incorporated into the Coordinated System Plan study. MISO regional issues identified in a regional Market Congestion Planning Study will be made available for incorporation into the Coordinated System Plan study between November of the first year and January of the second year of the two-year cycle. If MISO does not conduct a regional Market Congestion Planning Study as part of the MTEP, MISO will use MISO's most recent production cost models to identify regional issues and will provide the regional issues identified for incorporation into the Coordinated System Plan study between November of the first year and January of the second year of the two-year cycle. For matters addressing reliability specifically, MISO will use issues identified in the most recent MTEP report, available annually in December, and the reliability projects, submitted in September of the prior year being considered for inclusion in the current MTEP. MISO will include these projects in the regional issues made available for incorporation into Coordinated System Plan study.

ii. PJM regional reliability and Market Efficiency analyses will be used to identify regional issues that will be incorporated into the Coordinated System Plan study. Regional reliability analysis proceeds throughout the calendar year identifying PJM issues, including issues near the seam. These seams issues are presented to all stakeholders at the PJM Transmission Expansion Advisory Committee meetings and the PJM competitive window process, if eligible. PJM's long-term economic analysis cycles are conducted during two consecutive calendar years according to the schedule presented to stakeholders at the Transmission Expansion Advisory Committee meetings. The development of the economic model occurs throughout the first three quarters of the first year of the two-year study cycle and is made available for stakeholder review and comment prior to opening PJM's long-term proposal window later in the first year of the two-year study cycle. Both regional and interregional project proposals are submitted through the PJM project proposal windows consistent with Schedule 6, section 1.5.8(c) of the PJM Amended and Restated Operating Agreement. Interregional Project proposals entered into a PJM short-term or long-term proposal window will be analyzed along with PJM regional project proposals. Consistent with Schedule 6, section 1.5.8(d) of the PJM Amended and Restated Operating Agreement, PJM, in consultation with the Transmission Expansion Advisory Committee, shall determine the more efficient or cost effective transmission enhancements and expansions available for incorporation into the Coordinated System Plan study.

b. MISO and PJM regional models will be made available to the IPSAC for stakeholder review and comment in the first year of the two-year cycle as detailed below:

   i. MISO will make available its most recent MTEP cycle long-term multi-year power flow models for reliability analysis and multi-year production cost models with multiple economic Futures for economic analysis, annually by November 30.

   ii. PJM will make available its most recent regional reliability model that is updated annually in the first quarter of each calendar year. PJM's regional economic model is prepared according to the assumptions and schedule as discussed at the Transmission Expansion Advisory Committee meeting scheduled in the first quarter of year one of PJM's long-term regional planning cycle. The economic model is available for stakeholder review and feedback during the third quarter of the first year of PJM's two year planning cycle.

c. Stakeholder Interregional Project proposals, satisfying applicable regional and interregional requirements, will be accepted by PJM in its project proposal windows as detailed in Schedule 6 of the PJM Amended and Restated Operating Agreement.

d. Stakeholder identification of Interregional Project proposals satisfying the applicable regional and interregional requirements will be accepted in the MISO MTEP regional process approximately between January through March of the second year of the two-year cycle. A precise timeframe will be provided in each MTEP cycle.

e. The Parties will evaluate each Interregional Project proposal in its regional process, using the criteria and benefit determination in Sections 9.4.4.1 and 9.4.4.2 and applicable subsections, during the second year of the two-year cycle to determine if a project is eligible for inclusion in the respective regional plans. If recommended by the JRPC per Section 9.3.7.2(b)(xi), an Interregional Project must be presented to the respective Parties' Boards for approval and, if approved, in each Party's regional plan to become an Interregional Project. The Parties shall present the proposed projects, including any proposed Interregional Projects, to their respective Board of Directors or

Managers by December 31 of the second year of the two-year cycle.

i. In MISO, regional analysis typically occurs between February and September each year. Potential Interregional Projects will be evaluated against the MISO regional criteria and collectively with other potential regional projects to ensure cohesive benefits.

ii. In PJM, regional reliability analysis occurs annually. Regional market efficiency analysis occurs biennially. Interregional evaluations will occur in PJM's regional proposal window process as outlined in Section 9.3.7.2(b)(vii)(a)(ii).

(viii) The IPSAC will have the opportunity to provide input into the development of potential solutions. Feedback by the IPSAC stakeholders shall be provided to each region consistent with each region's regional processes for accepting project proposals. Potential solutions submitted through each region's respective planning processes specific to submitting project proposals shall be communicated between the Parties in a timely manner. The JRPC will be responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as an Interregional Project pursuant to Section 9.4.4.1. Proposed solution criteria and benefits shall be evaluated by each region pursuant to Sections 9.4.4.1 and 9.4.4.2 and applicable subsections.

(ix) Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements will be included in the Coordinated System Plan after the conclusion of the Coordinated System Plan study and applicable regional analyses.

(x) The JRPC shall produce and submit to the IPSAC for review reports documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended Interregional Projects with the associated cost allocation to the Parties pursuant to Section 9.4.4.2. The review of any proposed allocation of costs under the Coordinated System Plan pursuant to Section 9.4.4 will be accomplished during the periodically scheduled IPSAC meetings held during the course of the Coordinated System Plan study according to this Section 9.3.7.2. In addition, explanations why proposed Interregional Projects did not move forward in the process will be provided in the final Coordinated System Plan study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study reports. Results of, comments and responses to comments on the final Coordinated System Plan study report shall be posted on each Party's website. Fulfillment of the requirements of this subsection will be accomplished through periodically scheduled IPSAC meetings held during the course of the Coordinated System Plan study.

(xi) The JRPC's recommended Interregional Projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. These regional reviews will be integrated into the interregional process as further described in Sections 9.3 and 9.4. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties' Boards for approval and implementation using each Party's procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties' Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties' Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform the IPSAC of the outcome of each Party's review of the recommended Interregional Projects.

(c) Targeted Market Efficiency Project Study

The Coordinated System Plan study may include a Targeted Market Efficiency Project study consistent with Section 9.3.7.2(b)(iii). The Targeted Market Efficiency Project study will evaluate, analyze, and determine upgrades to remedy identified historical market-to-market congestion on Reciprocal Coordinated Flowgates on the PJM-MISO market border. Identified issues under this section will be expected to persist and are not expected to be substantially alleviated by system changes planned in the five (5) year planning horizon. Identification of issues will include, but not be limited to, the RTO's determination, based on historical operational information, of any historical flowgate congestion known to be caused by outage conditions. The RTOs will not consider for purposes of a Targeted Market Efficiency Project study, historical congestion on a Reciprocal Coordinated Flowgate caused by outages or will determine a proportionally reduced amount of congestion associated with that flowgate, as appropriate. Any Targeted Market Efficiency Project study initiated by the JRPC under this section will be conducted under the process defined for a Coordinated System Plan study, except as modified by this section and the following subsections.

(i) Issues identified in the Targeted Market Efficiency Project study will be reviewed to determine the cause of the market issues, including: (a) the specific limiting elements, (b) verification of the ratings of the limiting elements, (c) whether approved, planned system changes may alleviate the issue, (d) whether outages contribute to all or a portion of the historical congestion, (e) estimates of the cost of upgrading the limiting elements, and (f) whether upgrades to the limiting elements could substantially relieve the constraints;

(ii) Using the results of the review under subsection (i) and the applicable criteria of Section 9.4, the JRPC will provide to the IPSAC the criteria used to evaluate whether congestion is likely to be persistent. The JRPC will post results of the analysis for input from the IPSAC and will solicit proposals for Targeted Market Efficiency Projects that meet the criteria of Sections 9.3.7.2(c) and 9.4 applicable to a Targeted Market Efficiency Project;

(iii) The JRPC will determine the list of limiting element upgrades and Targeted Market Efficiency Project proposals to analyze the benefits to PJM and MISO for presentation to and input from the IPSAC;

(iv) Prior to making the determination outlined in Section 9.3.7.2(c)(vi) below, the JRPC will provide to the IPSAC any additional criteria used to evaluate potential Targeted Market Efficiency Project solutions;

(v) The JRPC will provide to the IPSAC for input an explanation of: (a) why the JRPC did not evaluate whether a potential Targeted Market Efficiency Project could economically address congestion on a particular congested Reciprocal Coordinated Flowgate, and (b) why a potential Targeted Market Efficiency Project that the JRPC evaluated is not recommended to the MISO and PJM Boards for approval;

*(*vi*)* Based on the analysis and stakeholder process conducted consistent with Sections 9.3.7.2(c) and 9.4, the JRPC will determine any Targeted Market Efficiency Project proposals to recommend to their respective Boards for approval; and

*(*vii*)* Solely for the purposes of conducting the Targeted Market Efficiency Project analysis, the regional processes referred to in

Section 9.3.7.2(b) will be the JRPC analysis conducted for the Targeted Market Efficiency Project study according to the scope and procedures developed under Sections 9.3.7.2(b)(ii) and 9.3.7.2(c). The joint JRPC analysis together with the associated stakeholder process will be sufficient for any resulting JRPC recommended Interregional Transmission Projects to be presented for approval to the respective RTOs' Board as described in 9.3.7.2(b)(xi).

9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.

When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party's OATT.

9.4.2 Network Upgrades Associated with Transmission Service Requests.

When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party's OATT.

9.4.3 Network Upgrades Associated with Incremental Auction Revenue Rights Requests.

When under Section 9.3.5 it is determined that the granting of an Incremental ARR request with respect to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Affected System's tariff provisions.

9.4.4 Network Upgrades Under Coordinated System Plan.

The Coordinated System Plan will identify Interregional Projects as: (i) Cross-Border Baseline Reliability Projects ("CBBRP"), (ii) Interregional Reliability Projects, (iii) Interregional Market Efficiency Projects, (iv) Interregional Public Policy Projects, and (v) Targeted Market Efficiency Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Interregional Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.4.1 Criteria for Project Designation as an Interregional Project:

Interregional Projects must be: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions. A project located solely in one region and paid for and benefiting only the adjacent region must meet the individual OATT requirements of the transmission planning region in which the project will be located to be eligible for inclusion in the local RTO's transmission plan in addition to the project criteria included in section 9.4.4.1.1, 9.4.4.1.2 or 9.4.4.1.3. In addition, an Interregional Project approved by each RTO for inclusion in its regional plan is subject to the construction obligation under each RTO's OATT. For purposes of interregional planning between MISO and PJM, ~~T~~these Interregional Projects will be designated in accordance with the following criteria:

9.4.4.1.1 Cross-Border Baseline Reliability Project Criteria:

Projects that meet all of the following criteria will be designated as CBBRPs:

(i) by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria;

(ii) the project must be a baseline reliability project as defined under the MISO or PJM Tariffs.

9.4.4.1.2 Interregional Reliability Project Criteria:

An Interregional Reliability Project must:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region's cost allocation process; and

(ii) by agreement of the JRPC, displace one or more reliability projects in either or both PJM and MISO as defined in their respective tariffs and more efficiently or cost-effectively meet applicable reliability criteria than the displaced reliability project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Reliability Project(s) addresses reliability needs that are currently being addressed with reliability projects in its regional transmission planning process and, if so, which reliability projects in that regional transmission planning process could be displaced by the proposed Interregional Reliability Project. Reliability projects in the MISO regional transmission planning process include Baseline Reliability Projects and Multi-Value Projects that meet Criterion 3 according to MISO's OATT. MISO and PJM will quantify the benefits of an Interregional Reliability Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan that would be displaced if the proposed Interregional Reliability Project was included in the plan.

9.4.4.1.3 Interregional Market Efficiency Project Criteria:

Interregional Market Efficiency Projects must meet the following criteria:

(i) is evaluated as part of a Coordinated System Plan or joint study process, as described in Section 9.3.7 of the JOA; and

(ii) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a Market Efficiency Project or a Multi-Value Project that meets Multi-Value Project Criterion 2 or Criterion 3 under the terms of Attachment FF of the MISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM RTEP or MISO OATT shall apply the Project Cost of the Interregional Market Efficiency Project and not the allocated cost; and

~~(iii) addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.~~

9.4.4.1.3.1 Determination of Benefits to Each RTO from an Interregional Market Efficiency Project:

The RTOs shall jointly evaluate the benefits to the ~~combined~~ MISO and PJM markets~~, and to each market individually, by evaluating multiple metrics using a multi-year analysis to determine whether a proposed project qualified as an Interregional Market Efficiency Project. The RTOs shall perform this evaluation~~ as follows:

(a) The RTOs shall utilize their respective tariffs' benefit metrics to analyze the anticipated annual economic benefits of construction of a proposed Interregional Market Efficiency Project to Transmission Customers of each RTO.

(b) The costs applied in the cost allocation calculation pursuant to Section 9.4.4.2.3 shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the Interregional Market Efficiency Project are determined from the estimated Interregional Market Efficiency Project installed costs and the fixed charge rate applicable in each respective RTO's regional process ~~to the constructing transmission owner(s)~~.

To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners' most recent after-tax embedded cost of capital weighted by each transmission owner's total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

(c) Using the cost allocated to each RTO pursuant to Section 9.4.4.2.3 of the JOA, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the MISO OATT.

9.4.4.1.4 Interregional Public Policy Project Criteria:

Interregional Public Policy Projects must meet the following criteria:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region's cost allocation process; and

(ii) by agreement of the JRPC, displace one or more regional projects addressing public policy in MISO or one or more public policy projects in PJM as defined in their respective tariffs and more efficiently or cost-effectively meet applicable public policy criteria than the displaced regional project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Public Policy Project(s) addresses public policy needs that are currently being addressed with public policy projects in its regional transmission planning process and, if so, which public policy projects in that regional transmission planning process could be displaced by the proposed Interregional Public Policy Project. Public policy projects in the MISO regional transmission planning process include Multi-Value Projects that meet Multi-Value Project Criterion 1 under the terms of Attachment FF to MISO's OATT. Public policy projects in the PJM regional transmission planning process include both economic and reliability projects. MISO and PJM will quantify the benefits of an Interregional Public Policy Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan for purposes of cost allocation that would be displaced if the proposed Interregional Public Policy Project was included in the plan.

9.4.4.1.5 Targeted Market Efficiency Project Criteria:

Upgrades associated with Targeted Market Efficiency Projects must meet the following criteria:

(i) Are evaluated as part of a Coordinated System Plan or joint study process as described in Section 9.3.7.2(c) and demonstrated to have an expectation for substantial relief of identified historical market efficiency congestion issues;

(ii) Have an estimated in-service date by the third-summer peak season from the year in which the project was approved;

(iii) Have an estimated installed cost less than $20 million in study year dollars;

(iv) Is determined to have expected future congestion relief, due to upgrade of that targeted Reciprocal Coordinated Flowgate, equal to the sum of annual congestion over the four (4) year period after the study year, that is equal to or greater than the estimated installed capital cost of the upgrade, including appropriate long term costs, in study year dollars, where:

a. Expected future congestion relief in the amount of the Reciprocal Coordinated Flowgate's anticipated reduction of historical congestion net of any anticipated increases in congestion on nearby flowgates based on the RTO analysis;

b. Historical congestion in PJM will be quantified in accordance with PJM OATT, Attachment K-Appendix, Section 5.1. It will include charges associated with Day-ahead and Real-time market congestion for Market Buyers, Generating Market Buyers, and Market Sellers;

c. Historical congestions in MISO will be quantified in accordance with MISO OATT, Sections 39.2.9 "Day-Ahead Energy and Operating Reserve Market Process" and 40.2.15 "Real-Time Energy and Operating Reserve Market Process." It will include charges associated with Day-Ahead and Real-Time market congestion for both load and generator buses; and

d. Annual congestion is the estimated average historical congestion based on the two historical calendar years prior to the study year.

(v) Is recommended by the JRPC as a Targeted Market Efficiency Project and approved by each RTO's Board.

9.4.4.1.5.1 Determination of Benefits of Each RTO from a Targeted Market Efficiency Project

The RTO shall jointly evaluate the benefits to the combined markets and to each RTO for each potential Targeted Market Efficiency Project resulting from Section 9.3.7.2(c), according to the following process:

(i) With input from IPSAC, determine the estimated total installed project capital cost in study year dollars;

(ii) Compare the estimated expected future congestion relief to the estimated project total installed capital cost in study year dollars. The estimated congestion relief shall equal or exceed the total installed capital cost in study year dollars, where:

a. Expected future congestion relief is the sum of each RTO's expected congestion relief, adjusted by market-to-market settlement payments.

9.4.4.2 Interregional Project Benefits and Shares:

The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO as set forth in the following subsections:

9.4.4.2.1 Cost Allocation for Cross-Border Baseline Reliability Projects

(a) **Method for Thermal Constraints:** The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO based on the relative contribution of the combined Load of each RTO to loading on the constrained facility requiring the need for the CBBRP. The loading contribution will be pre-determined using a joint RTO planning model developed and agreed to by the planning staffs of both RTOs. This model will form the basecase from which reliability needs on the combined systems will be determined for the Coordinated System Plan. The model, adjusted for the conditions driving the upgrade needs, will be used to calculate the DFAX for cost allocation purposes for each RTO, using a source of the aggregate of RTO generation (network resources) for each RTO to a sink of all Loads within that RTO. The DFAX is the appropriate distribution factor for the condition causing the upgrade; OTDF for contingency condition flow criteria violations, and PTDF for normal condition flow criteria violations. The DFAX calculation determines the MW flow impact attributable to each RTO on the constraint requiring the transmission system to be upgraded. The total load of each RTO for the condition modeled is multiplied by the DFAX associated with that RTO to determine the respective MW flow contribution of that RTO to the constraint. The RTOs will quantify the relative impact due to PJM's system and the relative impact due to MISO's system and then will allocate between PJM and MISO the load contributions to the reliability constraint on the system by calculating the relative impacts caused by each RTO. This methodology will determine the extent to which each RTO contributes to the need for a reliability upgrade consistent with the Coordinated System Plan modeling that determined the need for the upgrade. The MISO total load impacts will be allocated to MISO and the PJM total load impacts will be allocated to PJM. PJM and MISO will then reallocate their shares internally in accordance with their respective tariffs. By calculating the impacts in this manner, the RTOs will ensure that the relative contribution of each RTO (including both the aggravating and benefiting contributions of generation and load patterns within each RTO) to the need for a particular upgrade, is appropriately captured in the ensuing allocations, and that the allocation is consistent with the

Coordinated System Plan modeling that determined the need for the upgrade.

(b) **Method for Non-Thermal Constraints:** The JRPC will establish an interface, comprised of a number of transmission facilities, to serve as a surrogate for allocation of cost responsibility for non-thermal constraints. The interface will be established such that the aggregate flow on the interface best represents the non-thermal constraint which the CBBRP is proposed to alleviate. Allocation of cost responsibility for the non-thermal constraint will be determined by applying the procedures described in this Section to the interface serving as a surrogate for the constraint.

(c) **Method for Projects that Also Qualify As Interregional Reliability Projects:** For an Interregional Project that meets the criteria of both a CBBRP under Section 9.4.4.1.1 and an Interregional Reliability Project under Section 9.4.4.1.2, the cost will be allocated in accordance with the methodology set forth in Section 9.4.4.2.2.

9.4.4.2.2 Cost Allocation for an Interregional Reliability Project:

The cost of an Interregional Reliability Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Reliability 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 reliability projects as agreed to by the RTOs to the total of the present value(s) of the estimated costs of the displaced reliability projects in both regions that have selected the Interregional Reliability Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced reliability project's estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced reliability projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate proposed by the Transmission Owner that produces the cost estimate for the proposed project. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region's respective regional transmission planning process.

9.4.4.2.3 Cost Allocation for an Interregional Market Efficiency Project:

For Interregional Market Efficiency Projects that meet all of the qualifications in Section 9.4.4.1.3, the applicable project costs shall be allocated to the respective RTOs in proportion to the net present value of the total benefits calculated for each RTO pursuant to each RTO's respective tariff.

9.4.4.2.4 Cost Allocation for an Interregional Public Policy Project:

The cost of an Interregional Public Policy Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs for an Interregional Public Policy 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 public policy projects to the total of the present value(s) of the estimated costs of the displaced public policy projects in both regions that have selected the Interregional Public Policy Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced regional public policy project's estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced public policy projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate developed by MISO for cost estimates for projects under review by the MISO Board of Directors. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region's respective regional transmission planning process.

9.4.4.2.5 Cost Allocation for a Targeted Market Efficiency Project:

For Targeted Market Efficiency Projects that meet all of the qualifications in Section 9.4.4.1.5, the applicable project costs shall be allocated to the respective RTOs in proportion to the determination of expected future congestion relief for each RTO calculated pursuant to that Section.

~~9.4.4.3 Determination of Interregional Cost Allocation Share Outside of Coordinated System Plan:~~

~~Either RTO may request that a project be tested against the interregional cost allocation criteria during the interim periods between periodic formal releases of the Coordinated System Plan. The RTOs will conduct reviews between the formal cycles on at least an~~

~~annual basis. Such tests will be performed on the best available joint planning model, as determined by the JRPC.~~

~~The joint planning model will be a minimum 5-year horizon case, modeling peak summer conditions, and will be developed by February of each year. It will be based on the current RTEP basecase for PJM and the current MTEP basecase for MISO. The basecase developed by each RTO will be based on documented procedures, which, in turn, will guide the development of the joint RTO planning model. Any disputes that arise will be resolved through the dispute resolution procedures documented in Article XIV. Each year the model will be updated by the RTOs to include changes to long term firm transmission service, load forecast, topology changes, generation additions/retirements and any other relevant system changes that may have occurred since the previous years' basecase development. The joint RTO planning model will be available to any member of PJM or MISO.~~

9.4.4.3~~4~~ Cost Recovery of Interregional Allocation Shares:

The cost recovery of any share of cost of an Interregional Project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.

9.4.4.4~~5~~ Transmission Owners Filing Rights:

Nothing in this Section 9.4 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the applicable Tariffs and applicable agreements.

9.4.4.5~~6~~ Amendments:

The RTOs shall amend Article IX of this Agreement in accordance with the applicable tariffs and/or agreements.

Attachment B

Revisions to the PJM-MISO Joint Operating Agreement

(Clean Format)

9.3 Coordinated System Planning.

The primary purpose of coordinated transmission planning and development of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, enhance the competitiveness of electricity markets, or promote public policy. The Parties will conduct such coordinated planning as set forth in this Section 9.3 and subsections thereof.

9.3.1 <u>Single Party Planning</u>.

Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of the Party, NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents its annual regional plan prepared according to the procedures, methodologies, and business rules documented by the region. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party's OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties' respective systems.

9.3.2 <u>Coordinated System Plan</u>.

The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.7. The Coordinated System Plan shall also include the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses.

9.3.3 <u>Analysis of Interconnection Requests</u>.

In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. The process for coordination of interconnection studies and Network Upgrades is detailed below:

(a) Consistent with the data exchange provisions of the manuals, the Parties will exchange current power flow modeling data annually and as necessary for the study and coordination of interconnection requests. This will include the associated update of the other Party's relevant queue requests, contingency elements, monitoring elements data, and other data as may be required.

(b) The coordinated interconnection studies will determine the potential impact on the direct connect system and on the impacted Party. The direct connect system will be responsible for communicating coordinated interconnection study results to the direct connect interconnection customer.

(c) The Parties will coordinate and mutually agree on the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party.

(i) The transmission reinforcement and the study criteria used in the coordinated interconnection studies will conform to and incorporate provisions as outlined in the PJM and MISO Business Practices Manuals and the Parties' respective Tariffs.

(ii) The PJM and PJM transmission owner study and reinforcement criteria will apply to studies performed to determine impacts on the PJM transmission system when PJM evaluates the impact of MISO generation on PJM transmission facilities.

(iii) The MISO and MISO transmission owner study and reinforcement criteria will apply to studies performed to determine impacts on the MISO transmission system when MISO evaluates the impact of PJM generation on MISO transmission facilities.

(iv) The identification of all impacts on the Parties' transmission systems shall include a description of the required system reinforcement(s), an estimated planning level cost and construction schedule estimates of the system reinforcements.

(v) If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

The Parties will strive to minimize the costs associated with the coordinated study process.

(d) During the course of its interconnection studies, PJM shall monitor the MISO transmission system and provide to MISO the draft results of the potential impacts to the MISO transmission system. These potential impacts shall be included in the PJM System Impact Study report along with any information regarding the validity of these impacts and any transmission system reinforcements received from MISO and the MISO transmission owners.

(e) Following issuance of the PJM Feasibility Study report and after the Interconnection Customer executes the PJM System Impact Study Agreement, PJM shall forward to MISO, at a minimum of twice per year (April 15 and October 15), information necessary for MISO and the MISO transmission owners to study the impact of the PJM Interconnection Request(s) on the MISO transmission system. MISO and the MISO transmission owners shall study the impact(s) of the PJM Interconnection Request(s) on the MISO transmission system and provide draft results to PJM by:

(i) March 1 for PJM Interconnection Request(s) provided to MISO on or before October 15 of the previous year; and

(ii) September 1 for PJM Interconnection Request(s) provided to MISO on or before April 15 of the same year.

(f) During the determination of reinforcements for an Interconnection Request that are required to mitigate MISO constraint(s), PJM and MISO may identify other planned non-MISO reinforcement(s) that may alleviate such constraint(s) inside the MISO region. Under such circumstances, any PJM interconnection project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are placed into service. MISO shall determine the necessary injection limits associated with the PJM Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through MISO's affected system analysis are in service.

(g) During the course of MISO's interconnection studies, MISO shall monitor the PJM transmission system and provide to PJM the draft results of the potential impacts to the PJM transmission system. Those potential impacts shall be included in the MISO System Impact Study report along with any information regarding the validity of these impacts and possible mitigation received from PJM and the PJM transmission owners.

(h) Prior to commencing the MISO Definitive Planning Phase ("DPP") study, MISO shall forward to PJM, at a minimum of twice per year (January 1 and July 1), information necessary for PJM and the PJM transmission owners to study the impact of the MISO Interconnection Request(s) on the PJM transmission system. For the prescribed times when MISO provides this information to PJM, January 1 and July 1, PJM and the PJM transmission owners shall study the impact of the MISO Interconnection Request(s) on the PJM transmission system and provide the draft results to MISO by:

(i) March 31 for requests submitted to PJM on or before January 7 of the same year; and

(ii) September 29 for requests submitted to PJM on or before July 7 of the same year.

(i) During the determination of reinforcements for an Interconnection Request that are required to mitigate PJM constraint(s), PJM and MISO may identify other planned non-PJM reinforcement(s) that may alleviate a constraint inside the PJM region. Under such circumstances, any MISO interconnection project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are placed into service. PJM shall determine the necessary injection limits associated with the MISO Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through PJM's affected system analysis are in-service.

(j) If the coordinated interconnection study identifies constraints that require infrastructure additions on the impacted system to mitigate them, then the potentially impacted Party may perform its own analysis, in conjunction with the direct connect Party's Interconnection Studies. The interconnection customer whose project requires mitigation of constraint(s) found on an impacted Party's system shall enter into the appropriate Facilities Study agreement as required under the impacted Party's OATT.

(k) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(l) If the results of the coordinated study process indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the appropriate study report prepared for the interconnection customer.

(m) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(n) The Interconnection Customer whose project requires mitigation of constraint(s) found on an impacted Party's system shall enter into the appropriate Facilities Study Agreement as required under the impacted Party's Tariff.

(o) In the event that Network Upgrades are required on the potentially impacted Party's system, then interconnection service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(p) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. These lists will be presented annually to the IPSAC.

9.3.4 <u>Analysis of Long-Term Firm Transmission Service Requests</u>.
In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party's business practices manuals that are publicly available on each Party's website. Both Parties' manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon the posting to the OASIS of a request for service, the Party receiving the request will coordinate the study of the request, pursuant to each Party's business practices manuals, which will determine the potential impact on each Party's system. The Party receiving the request will be responsible for communicating coordinated study results to the customer requesting such service.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party's OASIS is unnecessary (i.e., the potentially impacted Party is "off the path"), then the potentially impacted Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process. The JRPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) If constraints are identified during the coordinated study on the impacted system, then the potentially impacted Party may perform its own analysis in conjunction with the studies performed by the Party that has received the request for service. The customer whose request for service requires mitigation of constraint(s) found on an impacted Party's system shall enter into the appropriate facilities study agreement as required under the impacted Party's OATT. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request's Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the Party receiving the request will identify the need for such Network Upgrades in the system impact study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party's system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

9.3.5 Analysis of Incremental Auction Revenue Rights Requests.

The Parties will coordinate, as deemed appropriate,[1] the conduct of any studies in response to a request for Incremental Auction Revenue Rights ("Incremental ARRs") ("Incremental ARR Request") made under one Party's tariff to determine its impact on the other Party's system. Results of such coordinated studies will be included in the impacts reported to the customer requesting Incremental ARRs as appropriate. Coordination of studies and Network Upgrades will include the following:

(a) The Parties will coordinate the base Firm Flow Entitlement values associated with the Coordinated Flowgates that may be impacted by the Incremental ARR Request.

(b) Upon receipt of an Incremental ARR Request or the review of studies related to the evaluation of such request, the Party receiving the Incremental ARR Request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the Incremental ARR Request will notify the other Party and convey the information provided in the request in addition to but not limited to the list of impacted constrained facilities.

(c) During the System Impact Study, the potentially impacted Party may participate in the coordinated study by providing input to the studies to be performed by the Party receiving the Incremental ARR Request. The potentially impacted Party shall determine the Network Upgrades, if any, needed to mitigate constraints on identified impacted facilities. The Parties shall coordinate to ensure any proposed Network Upgrades maintain the reliability of each Party's transmission system.

(d) Any coordinated System Impact Studies will be performed in accordance with the mutually agreed upon study timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement in accordance with applicable tariff provisions.

(e) During the Facilities Study, the potentially impacted Party may conduct its own Facilities Study as a part of Facilities Study being conducted by the Party that received the Incremental ARR request. The study cost estimates indicated in the Facility Study Agreement between the Party receiving the request and the Incremental ARR customer will reflect the costs and the associated roles of the study participants, including the potentially impacted Party. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the Incremental ARR Request shall collect from the Incremental ARR customer, and forward to the potentially impacted Party, the agreed upon payments associated with the performance of such studies.

(g) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted Party, the Party receiving the request will identify the need for such Network Upgrades in the System Impact Study prepared for the Incremental ARR customer.

(h) The construction of such Network Upgrades will be subject to the terms of the potentially impacted Party's tariff, the agreement among owners transferring functional control of transmission facilities to the control of the potentially impacted Party, and applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party's system, the Incremental ARR will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

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[1] Infra (b).

9.3.6 Analysis of Generator Deactivations (retirements and suspensions).

(a) The Party ("Noticed Party") receiving a new request from a generation owner to retire, deactivate, or mothball (or suspend operations as defined under the MISO Tariff) its generation unit will notify the other Party of such deactivation request no later than five (5) business days after receipt of the notice by the Noticed Party. The other Party ("Other Party") will determine if any study is required to evaluate potential impacts to its system due to the proposed generator deactivation in the Noticed Party's system. Any studies required due to a notice to deactivate (retire or suspend operations as defined under the MISO Tariff) will be performed under each Party's respective Tariff. Each Party's regional study results will be documented and provided to the other Party for informational purposes only.

(b) Both Parties will share all information necessary to evaluate potential impacts to their respective systems due to the notice. Such coordination shall provide for:

(i) Exchange of current power flow modeling data as necessary for the study and coordination of generator deactivations (retirements and suspensions). This will include the associated update of the other Party's generator availability, contingency elements, monitoring elements data, and other data as may be required.

(ii) Coordination by the Parties to align the assumptions of any analyses during development of the scope of any required studies. The scope design will include, as appropriate, evaluation of the transmission system against the criteria applicable to each Party for such studies.

(c) Following the exchange of information pursuant to section 9.3.6(b), the Other Party will conduct screening and evaluation of projects needed to mitigate identified impacts on its system. The Other Party will use reasonable efforts to perform an initial assessment and provide an indication of the impacts on its system to the Noticed Party within 65 days of receipt of the notice from the Noticed Party. The Other Party will provide a list of potential system reinforcements required on its system and estimated time for completion of those system reinforcements to the Noticed Party as soon as they are available.

(d) Each Party will be responsible for any regional Network Upgrades or other mitigation required on their respective system as a result of a request to deactivate (retirement or suspension).

(e) Any impact(s) on the Other Party's system identified in the analysis will not be used to determine the need to retain the generator requesting to deactivate.

(f) The identification of Network Upgrades required for generator deactivation (retirement or suspension) in the Other Party's system may require coordination through the JRPC. The Parties will endeavor to make such information available to the JRPC in a timely manner following publication of information through the Parties' regional processes. Additional coordination, as may be needed, will be conducted pursuant to the Coordinated System Plan study process as mutually agreed to be the Parties in accordance with the provisions of Section 9.3.7.

(i) The JRPC will incorporate any needed regional upgrades that may be identified by the generator deactivation studies coordinated pursuant to this section 9.3.6 into the annual review processes of Section 9.3.7 for the purpose of determining if there is a more efficient or cost effective Interregional Reliability Project that may replace one or more of the identified regional Network Upgrades required for the generator deactivation.

(ii) The JRPC will consider the results of the deactivation analyses forwarded to the committee at the next scheduled JRPC meeting or within 30 days of receipt of the completed study information from both Parties. Depending on the timing of the receipt of the study information, the JRPC will determine the most appropriate process for including the regional deactivation results into the development of the Coordinated System Plan. Such process will include IPSAC review according to the Coordinated System Plan process of Section 9.3.7.

Throughout the interregional review process any confidentiality provisions of the Parties Tariff's will be respected. Critical identified Interregional Reliability Projects for which the need to begin development is urgent will be presented to the Parties' Boards for approval as soon as possible after identification through the Coordinated System Plan study process. Other identified Interregional Reliability Projects presented to the Parties' Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade.

9.3.7 <u>Development of the Coordinated System Plan</u>.

9.3.7.1

Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties' systems. Each Party's annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Section, to obtain financial compensation due to the impact of another Party's plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:

(a) Integrate the Parties' respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation, market participant funded, or merchant transmission projects) and Network Upgrades identified jointly by the Parties, together with alternatives to Network Upgrades that were considered;

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to the integration described in the preceding part (a); and

(c) Describe results of the joint transmission analysis for the combined transmission systems, as well as explanations, as may be necessary, of the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

9.3.7.2

Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for a Coordinated System Plan study described in Section 9.3.7.2.a; and 2) Coordinated System Plan study described in Section 9.3.7.2.b.

(a) Determine the Need for a Coordinated System Plan Study.

(i) On an annual basis, beginning in the fourth quarter of each calendar year and continuing through the first quarter of the following calendar year, the Parties shall perform an annual evaluation of transmission issues identified by each Party including issues from the respective Party's market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed to schedule taking into consideration each Party's regional planning cycles.

(ii) The JRPC's annual review of transmission issues shall include the following steps:

a. Exchange of the following information during the fourth quarter of each calendar year or as specified below:

   i. Regional issues and newly approved regional projects located near the interface or expected to impact the adjacent region;

   ii. Newly identified regional transmission issues for which there is no proposed solution;

   iii. Interconnection and long-term firm transmission service requests under coordination by the Parties located near the interface or expected to impact the adjacent region will be exchanged pursuant to sections 9.3.3 and 9.3.4, respectively;

   iv. Market-to-market historical flowgate congestion between the Parties.

b. Joint review by the Parties of regional issues and solutions in January of each calendar year;

c. Receipt of Third Party issues in the first quarter of each calendar year;

d. Review of regional issues with input from stakeholders at the IPSAC meeting conducted during the first quarter of each calendar year; and

e. Decision by the JRPC on whether or not to conduct a Coordinated System Plan study.

(iii) The JRPC through each Party's respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to be held in the first quarter of each year to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting for consideration by the IPSAC and JRPC.

(iv) Within 45 days following the annual issues evaluation meeting with IPSAC in the first quarter of the calendar year, the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (1) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (2) if after two consecutive years in which a Coordinated System Plan study has not been performed, and one Party votes in favor of performing a Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study within five business days of the JRPC's decision.

(v) When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study and identify whether it is a targeted study as defined in this Section at (vi) or a more complex, two-year cycle study as defined in this Section at (vii).

(vi) If a Coordinated System Plan study includes targeted studies of particular areas, needs or potential expansions to ensure that the coordination of the reliability and efficiency of the Parties' transmission systems, then such targeted studies will be conducted during the first half of the calendar year. In years when the Coordinated System Plan study includes only targeted studies as defined herein, they may be conducted at any time during the calendar year but shall be completed within the calendar year in which they are identified.

(vii) A Coordinated System Plan study may include more complex, longer duration studies that may involve development of a joint model, as appropriate, to address reliability, market efficiency or public policy needs. Such studies will be conducted on a two-year cycle commencing in the third quarter of the first year of the two-year cycle, if the need is determined by the JRPC. A Coordinated System Plan study scheduled on a two-year cycle will conclude no later than the end of the second year of the two-year cycle.

a. For a Coordinated System Plan study scheduled on a two-year cycle, the JRPC will provide notice to the IPSAC in the fourth quarter of the year preceding commencement of the two-year study cycle.

b. The first year of the two-year study cycle will consist of model preparation and issue identification and be timed in accordance with each RTO's regional planning processes for model preparation and issue identification. Two-year study cycle activities and their interaction with regional activities are further described in the applicable sections of 9.3.7, particularly in section 9.3.7.2(b)(vii).

(viii) When a Coordinated System Plan study is determined to be necessary by the JRPC, the specific study process steps will depend on the type and scope of the study. The JRPC shall provide a schedule and binding deadlines for each step in the Coordinated System Plan study process no later than 15 days after the IPSAC meeting provided for in Section 9.3.7.2(b)(ii) following the JRPC's decision to initiate such study.

(b) Coordinated System Plan Study Process

(i) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(ii) The JRPC will develop a scope and procedure for the coordinated planning analysis. The scope of the studies will include evaluations of issues resulting from the annual coordinated review and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment at an IPSAC meeting scheduled no later than 30 days after the decision to conduct a Coordinated System Plan study.

(iii) Ad hoc study groups may be formed as needed to address localized seams issues or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented. Targeted studies will utilize the best available regional models for transmission and market efficiency analysis.

(iv) The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party's criteria. Stakeholder input will be solicited for potential remedies to identified issues, which includes stakeholder and transmission developer proposals for Interregional Projects. The study scope developed under Section 9.3.7.2(b)(ii) will include the schedule for acceptance of such stakeholder Interregional Project proposals including supporting analyses that address issues identified in the JRPC solicitation.

(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation of the transmission system against the reliability criteria, operational performance criteria, economic performance criteria, and public policy needs applicable to each Party.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. If the JRPC develops joint study models, the JRPC will do so consistent with the models and assumptions used for the regional planning cycle most recently completed, or underway, as appropriate. If the Coordinated System Plan study requires transmission evaluations driven by different regional needs (for example transmission that addresses any combination of needs including regional reliability, economics and public policy), then the coordination of studies, models, and assumptions will include the analyses appropriate to each region. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be accommodated. Known updates and revisions to models will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback to the JRPC regarding the study models.

(vii) When Coordinated System Plan studies are undertaken pursuant to a two-year study cycle defined in this Section at (a)(vii), the following schedule will be followed unless otherwise mutually agreed to by the Parties.

a. Parties will provide updated identification of regional issues identified in this Section at (a) by January of the second year of the two-year cycle.

i. If MISO conducts a regional Market Congestion Planning Study as part of the MTEP, MISO will use that Market Congestion Planning Study to identify the MISO regional issues that will be incorporated into the Coordinated System Plan study. MISO regional issues identified in a regional Market Congestion Planning Study will be made available for incorporation into the Coordinated System Plan study between November of the first year and January of the second year of the two-year cycle. If MISO does not conduct a regional Market Congestion Planning Study as part of the MTEP, MISO will use MISO's most recent production cost models to identify regional issues and will provide the regional issues identified for incorporation into the Coordinated System Plan study between November of the first year and January of the second year of the two-year cycle. For matters addressing reliability specifically, MISO will use issues identified in the most recent MTEP report, available annually in December, and the reliability projects, submitted in September of the prior year being considered for inclusion in the current MTEP. MISO will include these projects in the regional issues made available for incorporation into Coordinated System Plan study.

ii. PJM regional reliability and Market Efficiency analyses will be used to identify regional issues that will be incorporated into the Coordinated System Plan study. Regional reliability analysis proceeds throughout the calendar year identifying PJM issues, including issues near the seam. These seams issues are presented to all stakeholders at the PJM Transmission Expansion Advisory Committee meetings and the PJM competitive window process, if eligible. PJM's long-term economic analysis cycles are conducted during two consecutive calendar years according to the schedule presented to stakeholders at the Transmission Expansion Advisory Committee meetings. The development of the economic model occurs throughout the first three quarters of the first year of the two-year study cycle and is made available for stakeholder review and comment prior to opening PJM's long-term proposal window later in the first year of the two-year study cycle. Both regional and interregional project proposals are submitted through the PJM project proposal windows consistent with Schedule 6, section 1.5.8(c) of the PJM Amended and Restated Operating Agreement. Interregional Project proposals entered into a PJM short-term or long-term proposal window will be analyzed along with PJM regional project proposals. Consistent with Schedule 6, section 1.5.8(d) of the PJM Amended and Restated Operating Agreement, PJM, in consultation with the Transmission Expansion Advisory Committee, shall determine the more efficient or cost effective transmission enhancements and expansions available for incorporation into the Coordinated System Plan study.

b. MISO and PJM regional models will be made available to the IPSAC for stakeholder review and comment in the first year of the two-year cycle as detailed below:

i. MISO will make available its most recent MTEP cycle long-term multi-year power flow models for reliability analysis and multi-year production cost models with multiple economic Futures for economic analysis, annually by November 30.

ii. PJM will make available its most recent regional reliability model that is updated annually in the first quarter of each calendar year. PJM's regional economic model is prepared according to the assumptions and schedule as discussed at the Transmission Expansion Advisory Committee meeting scheduled in the first quarter of year one of PJM's long-term regional planning cycle. The economic model is available for stakeholder review and feedback during the third quarter of the first year of PJM's two year planning cycle.

c. Stakeholder Interregional Project proposals, satisfying applicable regional and interregional requirements, will be accepted by PJM in its project proposal windows as detailed in Schedule 6 of the PJM Amended and Restated Operating Agreement.

d. Stakeholder identification of Interregional Project proposals satisfying the applicable regional and interregional requirements will be accepted in the MISO MTEP regional process approximately between January through March of the second year of the two-year cycle. A precise timeframe will be provided in each MTEP cycle.

e. The Parties will evaluate each Interregional Project proposal in its regional process, using the criteria and benefit determination in Sections 9.4.4.1 and 9.4.4.2 and applicable subsections, during the second year of the two-year cycle to determine if a project is eligible for inclusion in the respective regional plans. If recommended by the JRPC per Section 9.3.7.2(b)(xi), an Interregional Project must be presented to the respective Parties' Boards for approval and, if approved, in each Party's regional plan to become an Interregional Project. The Parties shall present the proposed projects, including any proposed Interregional Projects, to their respective Board of Directors or Managers by December 31 of the second year of the two-year cycle.

i. In MISO, regional analysis typically occurs between February and September each year. Potential Interregional

Projects will be evaluated against the MISO regional criteria and collectively with other potential regional projects to ensure cohesive benefits.

ii. In PJM, regional reliability analysis occurs annually. Regional market efficiency analysis occurs biennially. Interregional evaluations will occur in PJM's regional proposal window process as outlined in Section 9.3.7.2(b)(vii)(a)(ii).

(viii) The IPSAC will have the opportunity to provide input into the development of potential solutions. Feedback by the IPSAC stakeholders shall be provided to each region consistent with each region's regional processes for accepting project proposals. Potential solutions submitted through each region's respective planning processes specific to submitting project proposals shall be communicated between the Parties in a timely manner. The JRPC will be responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as an Interregional Project pursuant to Section 9.4.4.1. Proposed solution criteria and benefits shall be evaluated by each region pursuant to Sections 9.4.4.1 and 9.4.4.2 and applicable subsections.

(ix) Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements will be included in the Coordinated System Plan after the conclusion of the Coordinated System Plan study and applicable regional analyses.

(x) The JRPC shall produce and submit to the IPSAC for review reports documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended Interregional Projects with the associated cost allocation to the Parties pursuant to Section 9.4.4.2. The review of any proposed allocation of costs under the Coordinated System Plan pursuant to Section 9.4.4 will be accomplished during the periodically scheduled IPSAC meetings held during the course of the Coordinated System Plan study according to this Section 9.3.7.2. In addition, explanations why proposed Interregional Projects did not move forward in the process will be provided in the final Coordinated System Plan study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study reports. Results of, comments and responses to comments on the final Coordinated System Plan study report shall be posted on each Party's website. Fulfillment of the requirements of this subsection will be accomplished through periodically scheduled IPSAC meetings held during the course of the Coordinated System Plan study.

(xi) The JRPC's recommended Interregional Projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. These regional reviews will be integrated into the interregional process as further described in Sections 9.3 and 9.4. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties' Boards for approval and implementation using each Party's procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties' Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties' Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform the IPSAC of the outcome of each Party's review of the recommended Interregional Projects.

(c) Targeted Market Efficiency Project Study

The Coordinated System Plan study may include a Targeted Market Efficiency Project study consistent with Section 9.3.7.2(b)(iii). The Targeted Market Efficiency Project study will evaluate, analyze, and determine upgrades to remedy identified historical market-to-market congestion on Reciprocal Coordinated Flowgates on the PJM-MISO market border. Identified issues under this section will be expected to persist and are not expected to be substantially alleviated by system changes planned in the five (5) year planning horizon. Identification of issues will include, but not be limited to, the RTO's determination, based on historical operational information, of any historical flowgate congestion known to be caused by outage conditions. The RTOs will not consider for purposes of a Targeted Market Efficiency Project study, historical congestion on a Reciprocal Coordinated Flowgate caused by outages or will determine a proportionally reduced amount of congestion associated with that flowgate, as appropriate. Any Targeted Market Efficiency Project study initiated by the JRPC under this section will be conducted under the process defined for a Coordinated System Plan study, except as modified by this section and the following subsections.

(i) Issues identified in the Targeted Market Efficiency Project study will be reviewed to determine the cause of the market issues, including: (a) the specific limiting elements, (b) verification of the ratings of the limiting elements, (c) whether approved, planned system changes may alleviate the issue, (d) whether outages contribute to all or a portion of the historical congestion, (e) estimates of the cost of upgrading the limiting elements, and (f) whether upgrades to the limiting elements could substantially relieve the constraints;

(ii) Using the results of the review under subsection (i) and the applicable criteria of Section 9.4, the JRPC will provide to the IPSAC the criteria used to evaluate whether congestion is likely to be persistent. The JRPC will post results of the analysis for input from the IPSAC and will solicit proposals for Targeted Market Efficiency Projects that meet the criteria of Sections 9.3.7.2(c) and 9.4 applicable to a Targeted Market Efficiency Project;

(iii) The JRPC will determine the list of limiting element upgrades and Targeted Market Efficiency Project proposals to analyze the benefits to PJM and MISO for presentation to and input from the IPSAC;

(iv) Prior to making the determination outlined in Section 9.3.7.2(c)(vi) below, the JRPC will provide to the IPSAC any additional criteria used to evaluate potential Targeted Market Efficiency Project solutions;

(v) The JRPC will provide to the IPSAC for input an explanation of: (a) why the JRPC did not evaluate whether a potential Targeted Market Efficiency Project could economically address congestion on a particular congested Reciprocal Coordinated Flowgate, and (b) why a potential Targeted Market Efficiency Project that the JRPC evaluated is not recommended to the MISO and PJM Boards for approval;

(vi) Based on the analysis and stakeholder process conducted consistent with Sections 9.3.7.2(c) and 9.4, the JRPC will determine any Targeted Market Efficiency Project proposals to recommend to their respective Boards for approval; and

(vii) Solely for the purposes of conducting the Targeted Market Efficiency Project analysis, the regional processes referred to in Section 9.3.7.2(b) will be the JRPC analysis conducted for the Targeted Market Efficiency Project study according to the scope and procedures developed under Sections 9.3.7.2(b)(ii) and 9.3.7.2(c). The joint JRPC analysis together with the associated stakeholder process will be sufficient for any resulting JRPC recommended Interregional Transmission Projects to be presented for approval to the respective RTOs' Board as described in 9.3.7.2(b)(xi).

9.4 Allocation of Costs of Network Upgrades.

9.4.1 <u>Network Upgrades Associated with Interconnections</u>.

When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party's OATT.

9.4.2 <u>Network Upgrades Associated with Transmission Service Requests</u>.

When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party's OATT.

9.4.3 <u>Network Upgrades Associated with Incremental Auction Revenue Rights Requests</u>.

When under Section 9.3.5 it is determined that the granting of an Incremental ARR request with respect to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Affected System's tariff provisions.

9.4.4 <u>Network Upgrades Under Coordinated System Plan</u>.

The Coordinated System Plan will identify Interregional Projects as: (i) Cross-Border Baseline Reliability Projects ("CBBRP"), (ii) Interregional Reliability Projects, (iii) Interregional Market Efficiency Projects, (iv) Interregional Public Policy Projects, and (v) Targeted Market Efficiency Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Interregional Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.4.1 Criteria for Project Designation as an Interregional Project:

Interregional Projects must be: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions. A project located solely in one region and paid for and benefiting only the adjacent region must meet the individual OATT requirements of the transmission planning region in which the project will be located to be eligible for inclusion in the local RTO's transmission plan in addition to the project criteria included in section 9.4.4.1.1, 9.4.4.1.2 or 9.4.4.1.3. In addition, an Interregional Project approved by each RTO for inclusion in its regional plan is subject to the construction obligation under each RTO's OATT. For purposes of interregional planning between MISO and PJM, these Interregional Projects will be designated in accordance with the following criteria:

9.4.4.1.1 Cross-Border Baseline Reliability Project Criteria:

Projects that meet all of the following criteria will be designated as CBBRPs:

(i) by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria;

(ii) the project must be a baseline reliability project as defined under the MISO or PJM Tariffs.

9.4.4.1.2 Interregional Reliability Project Criteria:

An Interregional Reliability Project must:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region's cost allocation process; and

(ii) by agreement of the JRPC, displace one or more reliability projects in either or both PJM and MISO as defined in their respective tariffs and more efficiently or cost-effectively meet applicable reliability criteria than the displaced reliability project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Reliability Project(s) addresses reliability needs that are currently being addressed with reliability projects in its regional transmission planning process and, if so, which reliability projects in that regional transmission planning process could be displaced by the proposed Interregional Reliability Project. Reliability projects in the MISO regional transmission planning process include Baseline Reliability Projects and Multi-Value Projects that meet Criterion 3 according to MISO's OATT. MISO and PJM will quantify the benefits of an Interregional Reliability Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan that would be displaced if the proposed Interregional Reliability Project was included in the plan.

9.4.4.1.3 Interregional Market Efficiency Project Criteria:

Interregional Market Efficiency Projects must meet the following criteria:

(i) is evaluated as part of a Coordinated System Plan or joint study process, as described in Section 9.3.7 of the JOA; and

(ii) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a Market Efficiency Project or a Multi-Value Project that meets Multi-Value Project Criterion 2 or Criterion 3 under the terms of Attachment FF of the MISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM RTEP or MISO OATT shall apply the Project Cost of the Interregional Market Efficiency Project and not the allocated cost; and

9.4.4.1.3.1 Determination of Benefits to Each RTO from an Interregional Market Efficiency Project:

The RTOs shall jointly evaluate the benefits to the MISO and PJM markets as follows:

(a) The RTOs shall utilize their respective tariffs' benefit metrics to analyze the anticipated annual economic benefits of construction of a proposed Interregional Market Efficiency Project to Transmission Customers of each RTO.

(b) The costs applied in the cost allocation calculation pursuant to Section 9.4.4.2.3 shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the Interregional Market Efficiency Project are determined from the estimated Interregional Market Efficiency Project installed costs and the fixed charge rate applicable in each respective RTO's regional process.

To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners' most recent after-tax embedded cost of capital weighted by each transmission owner's total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

(c) Using the cost allocated to each RTO pursuant to Section 9.4.4.2.3 of the JOA, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the MISO OATT.

9.4.4.1.4 Interregional Public Policy Project Criteria:

Interregional Public Policy Projects must meet the following criteria:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region's cost allocation process; and

(ii) by agreement of the JRPC, displace one or more regional projects addressing public policy in MISO or one or more public policy projects in PJM as defined in their respective tariffs and more efficiently or cost-effectively meet applicable public policy criteria than the displaced regional project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Public Policy Project(s) addresses public policy needs that are currently being addressed with public policy projects in its regional transmission planning process and, if so, which public policy projects in that regional transmission planning process could be displaced by the proposed Interregional Public Policy Project. Public policy projects in the MISO regional transmission planning process include Multi-Value Projects that meet Multi-Value Project Criterion 1 under the terms of Attachment FF to MISO's OATT. Public policy projects in the PJM regional transmission planning process include both economic and reliability projects. MISO and PJM will quantify the benefits of an Interregional Public Policy Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan for purposes of cost allocation that would be displaced if the proposed Interregional Public Policy Project was included in the plan.

9.4.4.1.5 Targeted Market Efficiency Project Criteria:

Upgrades associated with Targeted Market Efficiency Projects must meet the following criteria:

(i) Are evaluated as part of a Coordinated System Plan or joint study process as described in Section 9.3.7.2(c) and demonstrated to have an expectation for substantial relief of identified historical market efficiency congestion issues;

(ii) Have an estimated in-service date by the third-summer peak season from the year in which the project was approved;

(iii) Have an estimated installed cost less than $20 million in study year dollars;

(iv) Is determined to have expected future congestion relief, due to upgrade of that targeted Reciprocal Coordinated Flowgate, equal to the sum of annual congestion over the four (4) year period after the study year, that is equal to or greater than the estimated installed capital cost of the upgrade, including appropriate long term costs, in study year dollars, where:

a. Expected future congestion relief in the amount of the Reciprocal Coordinated Flowgate's anticipated reduction of historical congestion net of any anticipated increases in congestion on nearby flowgates based on the RTO analysis;

b. Historical congestion in PJM will be quantified in accordance with PJM OATT, Attachment K-Appendix, Section 5.1. It will include charges associated with Day-ahead and Real-time market congestion for Market Buyers, Generating Market Buyers, and Market Sellers;

c. Historical congestions in MISO will be quantified in accordance with MISO OATT, Sections 39.2.9 "Day-Ahead Energy and Operating Reserve Market Process" and 40.2.15 "Real-Time Energy and Operating Reserve Market Process." It will include charges associated with Day-Ahead and Real-Time market congestion for both load and generator buses; and

d. Annual congestion is the estimated average historical congestion based on the two historical calendar years prior to the study year.

(v) Is recommended by the JRPC as a Targeted Market Efficiency Project and approved by each RTO's Board.

9.4.4.1.5.1 Determination of Benefits of Each RTO from a Targeted Market Efficiency Project

The RTO shall jointly evaluate the benefits to the combined markets and to each RTO for each potential Targeted Market Efficiency Project resulting from Section 9.3.7.2(c), according to the following process:

(i) With input from IPSAC, determine the estimated total installed project capital cost in study year dollars;

(ii) Compare the estimated expected future congestion relief to the estimated project total installed capital cost in study year dollars. The estimated congestion relief shall equal or exceed the total installed capital cost in study year dollars, where:

a. Expected future congestion relief is the sum of each RTO's expected congestion relief, adjusted by market-to-market settlement payments.

9.4.4.2 Interregional Project Benefits and Shares:

The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO as set forth in the following subsections:

9.4.4.2.1 Cost Allocation for Cross-Border Baseline Reliability Projects

(a) **Method for Thermal Constraints:** The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO based on the relative contribution of the combined Load of each RTO to loading on the constrained facility requiring the need for the CBBRP. The loading contribution will be pre-determined using a joint RTO planning model developed and agreed to by the planning staffs of both RTOs. This model will form the basecase from which reliability needs on the combined systems will be determined for the Coordinated System Plan. The model, adjusted for the conditions driving the upgrade needs, will be used to calculate the DFAX for cost allocation purposes for each RTO, using a source of the aggregate of RTO generation (network resources) for each RTO to a sink of all Loads within that RTO. The DFAX is the appropriate distribution factor for the condition causing the upgrade; OTDF for contingency condition flow criteria violations, and PTDF for normal condition flow criteria violations. The DFAX calculation determines the MW flow impact attributable to each RTO on the constraint requiring the transmission system to be upgraded. The total load of each RTO for the condition modeled is multiplied by the DFAX associated with that RTO to determine the respective MW flow contribution of that RTO to the constraint. The RTOs will quantify the relative impact due to PJM's system and the relative impact due to MISO's system and then will allocate between PJM and MISO the load contributions to the reliability constraint on the system by calculating the relative impacts caused by each RTO. This methodology will determine the extent to which each RTO contributes to the need for a reliability upgrade consistent with the Coordinated System Plan modeling that determined the need for the upgrade. The MISO total load impacts will be allocated to MISO and the PJM total load impacts will be allocated to PJM. PJM and MISO will then reallocate their shares internally in accordance with their respective tariffs. By calculating the impacts in this manner, the RTOs will ensure that the relative contribution of each RTO (including both the aggravating and benefiting contributions of generation and load patterns within each RTO) to the need for a particular upgrade, is appropriately captured in the ensuing allocations, and that the allocation is consistent with the Coordinated System Plan modeling that determined the need for the upgrade.

(b) **Method for Non-Thermal Constraints:** The JRPC will establish an interface, comprised of a number of transmission facilities, to serve as a surrogate for allocation of cost responsibility for non-thermal constraints. The interface will be established such that the aggregate flow on the interface best represents the non-thermal constraint which the CBBRP is proposed to alleviate. Allocation of cost responsibility for the non-thermal constraint will be determined by applying the procedures described in this Section to the interface serving as a surrogate for the constraint.

(c) **Method for Projects that Also Qualify As Interregional Reliability Projects:** For an Interregional Project that meets the criteria of both a CBBRP under Section 9.4.4.1.1 and an Interregional Reliability Project under Section 9.4.4.1.2, the cost will be allocated in accordance with the methodology set forth in Section 9.4.4.2.2.

9.4.4.2.2 Cost Allocation for an Interregional Reliability Project:

The cost of an Interregional Reliability Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Reliability 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 reliability projects as agreed to by the RTOs to the total of the present value(s) of the estimated costs of the displaced reliability projects in both regions that have selected the Interregional Reliability Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced reliability project's estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced reliability projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate proposed by the Transmission Owner that produces the cost estimate for the proposed project. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region's respective regional transmission planning process.

9.4.4.2.3 Cost Allocation for an Interregional Market Efficiency Project:

For Interregional Market Efficiency Projects that meet all of the qualifications in Section 9.4.4.1.3, the applicable project costs shall be allocated to the respective RTOs in proportion to the net present value of the total benefits calculated for each RTO pursuant to each RTO's respective tariff.

9.4.4.2.4 Cost Allocation for an Interregional Public Policy Project:

The cost of an Interregional Public Policy Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs for an Interregional Public Policy 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 public policy projects to the total of the present value(s) of the estimated costs of the displaced public policy projects in both regions that have selected the Interregional Public Policy Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced regional public policy project's estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced public policy projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate developed by MISO for cost estimates for projects under review by the MISO Board of Directors. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region's respective regional transmission planning process.

9.4.4.2.5 Cost Allocation for a Targeted Market Efficiency Project:

For Targeted Market Efficiency Projects that meet all of the qualifications in Section 9.4.4.1.5, the applicable project costs shall be allocated to the respective RTOs in proportion to the determination of expected future congestion relief for each RTO calculated pursuant to that Section.

9.4.4.3 Cost Recovery of Interregional Allocation Shares:

The cost recovery of any share of cost of an Interregional Project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.

9.4.4.4 Transmission Owners Filing Rights:

Nothing in this Section 9.4 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the applicable Tariffs and applicable agreements.

9.4.4.5 Amendments:

The RTOs shall amend Article IX of this Agreement in accordance with the applicable tariffs and/or agreements.