155 FERC ¶ 61,058
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Northern Indiana Public Service Company Docket No. EL13-88-000

v.

Midcontinent Independent System Operator, Inc. and
PJM Interconnection, L.L.C.

ORDER ON COMPLAINT AND TECHNICAL CONFERENCE

(Issued April 21, 2016)

1. On September 11, 2013, Northern Indiana Public Service Company (NIPSCO) filed a complaint pursuant to sections 206, 306, and 309 of the Federal Power Act (FPA)[1] and Rule 206 of the Commission's Rules of Practice and Procedure[2] against Midcontinent Independent System Operator, Inc. (MISO) and PJM Interconnection, L.L.C. (PJM) (Complaint). NIPSCO requests that the Commission order MISO and PJM to reform the interregional transmission planning process of the Joint Operating Agreement between MISO and PJM (JOA).

2. For the reasons discussed below, we grant the Complaint, in part, and deny the Complaint, in part, and require MISO and PJM to make compliance filings and informational filings as described further herein.

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[1] 16 U.S.C. §§ 824e, 825e, 825h (2012).

[2] 18 C.F.R. § 385.206 (2015).

I. Background

3. NIPSCO is a vertically-integrated Indiana corporation engaged in the generation, transmission and distribution of energy at the wholesale and retail levels. NIPSCO is an electric load-serving entity and a transmission owning member of MISO.[3] NIPSCO's system lies between the PJM systems of Commonwealth Edison Company (ComEd) and American Electric Power's (AEP) Indiana & Michigan Power Company and the rest of PJM's system. The interconnections of NIPSCO's transmission network with the transmission networks of ComEd and AEP are at the "seams" of MISO and PJM.

4. Both MISO and PJM are Commission-approved regional transmission organizations (RTO) and signatories to the JOA.[4] MISO and PJM filed the JOA on December 31, 2003 pursuant to earlier Commission orders.[5] The Commission conditionally accepted the JOA on March 18, 2004, and directed MISO and PJM to make further revisions concerning sharing of transmission owner plans and coordination in development of regional transmission plans.[6] MISO and PJM submitted a compliance filing on April 2, 2004, and the Commission accepted the changes on August 5, 2004.[7] Since 2004, MISO and PJM have filed a number of revisions to the JOA.

5. In 2009, MISO and PJM filed a proposal for interregional cost allocation related to interregional economic transmission projects, which was accepted by the Commission on November 3, 2009.[8] The costs of these projects are allocated between MISO and PJM

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[3] Complaint at 12.

[4] *Id.* at 13.

[5] *See Midwest Indep. Transmission Sys. Operator, Inc. and PJM Interconnection*, L.L.C., Docket No. ER04-375-000, Submission of Joint Operating Agreement at 4; *Alliance Cos.*, 103 FERC ¶ 61,274, at PP 22-23 (2003) (Alliance Order).

[6] *See Midwest Indep. Transmission Sys. Operator, Inc. and PJM Interconnection, L.L.C.*, 106 FERC ¶ 61,251 (2014).

[7] *See Midwest Indep. Transmission Sys. Operator, Inc. and PJM Interconnection, L.L.C.*, 108 FERC ¶ 61,143 (2004).

[8] *See Midwest Indep. Transmission Sys. Operator, Inc. and PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,102, at P 27 (2009) (November 2009 Order). At the time, the JOA called interregional economic transmission projects Cross Border Market Efficiency Projects. MISO and PJM subsequently changed the name of these projects to Interregional Market Efficiency Projects (*PJM Interconnection, L.L.C.*, 155 FERC

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"in proportion to the present value of the RTO's share of the annual benefits that are calculated for the proposed project."[9] The costs would then be allocated within each RTO based on the benefit formulas that were already used by MISO and PJM for cost allocation of their own economic projects on a regional basis.

II. **Complaint**[10]

6. NIPSCO states that it has filed the Complaint to remedy flaws in the interregional transmission planning provisions of the JOA. NIPSCO also argues that the Order No. 1000[11] interregional compliance filings by MISO and PJM do not comply with Order No. 1000. NIPSCO argues that assuming, *arguendo*, that MISO and PJM have complied with Order No. 1000, given the specific orders approving the MISO-PJM seam in particular, and the specific facts and circumstances surrounding the state of affairs along the MISO-PJM seam, the Commission should take action to ensure that customers' rates remain just and reasonable.[12] NIPSCO states that elements of its proposed reforms to the JOA process may arguably be considered within the scope of MISO's and PJM's Order No. 1000 interregional compliance filings, while other elements may be outside the mandates of Order No. 1000.[13]

7. NIPSCO argues that, to date, no transmission project has been approved under the JOA. NIPSCO argues that the highly interconnected and highly utilized nature of the MISO-PJM seam demonstrates that the transmission planning process the RTOs rely on

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¶ 61,008 (2016)). In this order, we refer to such projects as interregional economic transmission projects.

[9] *See* November 2009 Order, 129 FERC ¶ 61,102 at P 5.

[10] Further details of the Complaint will be explained throughout this order.

[11] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, 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).

[12] Complaint at 4.

[13] *Id.* at 2. NIPSCO submitted a protest to MISO's and PJM's Order No. 1000 interregional compliance filings in Docket Nos. ER13-1924-000, ER13-1943-000, ER13-1944-000, and ER13-1945-000. The Complaint and protest are essentially identical.

to meet their interregional transmission planning responsibilities is unreasonably flawed.[14] NIPSCO also asserts that there have been significant congestion costs and operating issues along the MISO-PJM seam and on the NIPSCO interface in particular. NIPSCO submits that, while the use of market-to-market redispatch and associated payments for day-to-day operations makes sense, the deeper problem is that this approach has served as a solution to interregional constraints rather than building long-term solutions to long-standing congested flowgates.[15]

8. NIPSCO submits that, to make the JOA interregional transmission planning provisions just and reasonable, the Commission should order MISO and PJM to implement the following six reforms through revisions to the JOA.

9. First, NIPSCO states that the Commission should require the MISO-PJM cross-border planning process to run concurrently with the MISO Transmission Expansion Plan (MTEP) and the PJM Regional Transmission Expansion Plan (RTEP) processes rather than after the MTEP and RTEP cycles, and NIPSCO proposes a schedule for doing so.[16]

10. Second, NIPSCO states that there should be consistency between the MISO and PJM transmission planning analyses.[17] Specifically, NIPSCO states that the Commission should require MISO and PJM to develop and use a single combined MTEP/RTEP model that uses the same modeling assumptions for annual reliability and economic transmission planning related to seams-related transmission issues.[18]

11. Third, NIPSCO states that the Commission should require MISO and PJM to develop and jointly agree upon a single common set of criteria for the approval of interregional economic transmission projects.[19]

12. Fourth, NIPSCO states that the Commission should require MISO and PJM to amend the criteria for approval of an interregional economic transmission project so that

[14] Complaint at 5.

[15] *Id.* at 24.

[16] *Id.* at 6-7 and Attachment A.

[17] *Id.* at 7-8.

[18] *Id.* at 7.

[19] *Id.* at 8-9, 43-46.

it addresses all known benefits including, more specifically, avoidance of future market-to-market payments made to reallocate short-term transmission capacity in the real-time operation of the system.[20]

13. Fifth, NIPSCO states that the Commission should require MISO and PJM to have a process for joint planning and cost allocation of lower-voltage and lower-cost transmission upgrades.[21]

14. Sixth, NIPSCO states that MISO and PJM must improve the processes within the JOA with respect to new generator interconnections and generation retirements.[22]

III. Subsequent Events

15. On December 19, 2013, the Commission issued an order holding the Complaint in abeyance pending further Commission action in other proceedings, including MISO and PJM's proposed compliance with the interregional coordination and cost allocation requirements of Order No. 1000.[23]

16. On December 18, 2014, the Commission issued an order addressing MISO and PJM's proposed compliance with the interregional coordination and cost allocation requirements of Order No. 1000.[24] In that order, the Commission stated that NIPSCO's protest to the MISO and PJM interregional compliance filings raised the same issues that NIPSCO raised in its Complaint against MISO and PJM. The Commission also stated that it would address the issues NIPSCO raised in its protest in the MISO-PJM Order No. 1000 interregional compliance proceeding in the Complaint proceeding. In addition, the Commission noted that its determinations in the order addressing MISO and PJM's proposed compliance with the interregional coordination and cost allocation requirements

[20] *Id.* at 9-10, 46-48.

[21] *Id.* at 10, 48-50.

[22] *Id.* at 11, 50-55.

[23] *Northern Indiana Public Service Co. v. Midcontinent Indep. Sys. Operator, Inc. and PJM Interconnection, L.L.C.*, 145 FERC ¶ 61,256, at P 21 (2013) (Abeyance Order).

[24] *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,250 (2014) (MISO-PJM First Interregional Compliance Order).

of Order No. 1000 do not preclude any Commission action on the issues raised in the Complaint.[25]

17. Also on December 18, 2014, the Commission issued an order directing Commission staff to convene a technical conference to explore issues raised in the Complaint related to the JOA and the MISO-PJM seam and established a refund effective date of September 11, 2013.[26] The Commission directed Commission staff to issue a request for comments on these issues prior to the technical conference to inform the technical conference discussion.[27]

18. On February 12, 2015, Commission staff issued a request for pre-technical conference comments and reply comments. Comments were submitted by: NIPSCO; Southern Indiana Gas & Electric Company (Southern Indiana); MISO and PJM; American Transmission Company LLC (ATC); Generator Group; [28] Indiana Utility Regulatory Commission; AEP[29]and Exelon; Xcel Energy Services Inc. (Xcel);[30] American Wind Energy Association (AWEA); ITC;[31] and Wisconsin Electric Power

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[25] MISO-PJM First Interregional Compliance Order, 149 FERC ¶ 61,250 at P 28.

[26] *Northern Indiana Public Service Co. v. Midcontinent Indep. Sys. Operator, Inc. and PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,248 (2014) (Technical Conference Order).

[27] Technical Conference Order, 149 FERC ¶ 61,248 at P 35.

[28] Generator Group is comprised of EDP Renewables North America LLC; E.ON Climate & Renewables North America, LLC; and Hoosier Wind Project, LLC.

[29] AEP is comprised of American Electric Power Service Corporation, on behalf of its affiliates Transource Energy, LLC; Appalachian Power Company; Indiana Michigan Power Company; Kentucky Power Company; Kingsport Power Company; Ohio Power Company; Wheeling Power Company; AEP Appalachian Transmission Company; AEP Indiana Michigan Transmission Company; AEP Kentucky Transmission Company; AEP Ohio Transmission Company; and AEP West Virginia Transmission Company.

[30] Xcel filed on behalf of its utility operating company affiliates Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation.

[31] ITC is comprised of International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Mid-Atlantic Development LLC; and ITC Midcontinent Development, LLC.

Company (Wisconsin Electric). Reply comments were submitted by: ITC; Generator Group; AEP and Exelon; and NIPSCO.

19. Commission staff convened the technical conference on June 15, 2015.

20. On July 15, 2015, Indiana Utility Regulatory Commission (Indiana Commission), PSEG Companies;[32] ITC, and NIPSCO submitted post-technical conference comments.

21. Also on July 15, 2015, the Commission issued a notice requesting further post-technical conference comments, due on or before August 14, 2015, and reply comments, due on or before August 31, 2015.

22. On August 14, 2015, post-technical conference comments were submitted by: NIPSCO; ITC; MISO and PJM; AEP and Exelon; and Generator Group. On August 31, 2015, post-technical conference reply comments were submitted by: NIPSCO; ITC; AEP and Exelon; and Generator Group.

23. On September 3, 2015, PJM filed a motion for leave to reply out of time and reply. On September 28, 2015, NIPSCO filed an answer to PJM's motion and reply. On October 13, 2015, PJM filed an answer to NIPSCO's answer.

24. On February 3, 2016, Generator Group filed supplemental comments. On February 18, 2016 and February 22, 2016, respectively, Xcel and MISO Transmission Owners[33] filed answers to Generator Group's supplemental comments. On February 29,

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[32] PSEG Companies are Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[33] MISO Transmission Owners for this filing consist of Ameren Services Company, as agent for Union Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; ATC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; City Water, Light & Power; Cleco Power LLC; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, Inc.; East Texas Electric Cooperative; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; MidAmerican Energy Company; Minnesota Power and Superior Water, L&P; Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power Inc.; Southern Illinois Power Cooperative; Southern

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2016, Generator Group filed an answer to Xcel's and MISO Transmission Owners' answers. On March 31, 2016, MISO filed an answer to the Generator Group's supplemental concerns. On April 8, 2016, NIPSCO filed an answer to MISO's answer.

25. BHE US Transmission; Midwest TDUs;[34] South Mississippi Electric Power Association, Cleco Power LLC; Entergy Services, Inc.; and Arkansas Electric Cooperative Corporation filed motions to intervene out-of-time.

IV. Discussion

A. Procedural Matters

26. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2015), we grant the late-filed motions to intervene submitted by BHE US Transmission; Midwest TDUs; South Mississippi Electric Power Association, Cleco Power LLC; Entergy Services, Inc.; and Arkansas Electric Cooperative Corporation given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.[35]

27. Pursuant to Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2015), we will accept the answers filed because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

28. As discussed further below, we find that NIPSCO has, in part, met its burden under section 206 of the FPA to show that the JOA and MISO tariff are unjust, unreasonable, unduly discriminatory, or preferential. Accordingly, we will grant NIPSCO's Complaint in part and deny it in part and direct MISO and PJM to submit revisions to the JOA and MISO tariff, as discussed further below.

Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

[34] Midwest TDUs are Madison Gas & Electric Company; Missouri Joint Municipal Electric Utility Commission; Missouri River Energy Services; and WPPI Energy.

[35] The Commission previously found that parties that had submitted notices of intervention and timely, unopposed motions to intervene make the entities that filed them parties to this proceeding. *See* Abeyance Order, 145 FERC ¶ 61,256 at P 19.

1. Transmission Planning Cycles

a. JOA

29. As defined in the JOA, the primary purpose of coordinated transmission planning and development of the Coordinated System Plan Study 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.[36]

30. In the JOA, MISO and PJM agree to assist in preparing a Coordinated System Plan Study, which integrates their respective regional transmission plans, specifies actions to resolve any impacts along the MISO-PJM seam due to this integration, and describes the results of the joint transmission analysis for the combined MISO-PJM transmission system.[37] Coordinated regional transmission planning and joint planning between MISO and PJM are conducted through two formal committees: (1) the Joint RTO Planning Committee, comprised of staff representatives from both RTOs, and (2) the Interregional Planning Stakeholder Advisory Committee, a committee open to stakeholders from both regions. The Joint RTO Planning Committee is responsible for, among other things, conducting an annual review of transmission issues identified by MISO and PJM, determining if a Coordinated System Plan Study should be performed, and developing various models to perform coordinated system planning.[38] The Interregional Planning Stakeholder Advisory Committee facilitates stakeholder review and provides input into this process.[39]

31. Following an annual review of transmission issues identified by MISO and PJM, the Joint RTO Planning Committee will determine, with input from the Interregional Planning Stakeholder Advisory Committee, whether a Coordinated System Plan Study is needed. A study is initiated if (1) both MISO and PJM vote in favor of performing the study, or (2) if after two consecutive years of not performing a study, either MISO or PJM votes to do so. When a Coordinated System Plan Study is initiated, the Joint RTO Planning Committee determines a start date for the study, not to exceed 180 calendar

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[36] JOA, § 9.3.

[37] *Id.* § 9.3.5.1.

[38] *Id.* § 9.1.1.

[39] *Id.* § 9.1.2.

days from the date of the Joint RTO Planning Committee's determination to perform the study, unless MISO and PJM agree to an alternative start date.[40]

32. MISO and PJM will be responsible for providing technical support required to complete the Coordinated System Plan Study. The Joint RTO Planning Committee will develop the scope and procedures for the study, including evaluation of transmission issues identified by MISO and PJM in the annual review, and a schedule of Interregional Planning Stakeholder Advisory Committee review and input. Ad hoc study groups may be formed 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 MISO's and PJM's systems. The Coordinated System Plan Study will consider identified transmission issues reviewed by the Joint RTO Planning Committee and Interregional Planning Stakeholder Advisory Committee for further evaluation of potential solutions, including stakeholder and transmission developer proposals for Interregional Projects. At the conclusion of the Coordinated System Plan Study, the Joint RTO Planning Committee produces and provides to the Interregional Planning Stakeholder Advisory Committee for review a Coordinated System Plan, which includes the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended Interregional Projects addressing the identified issues. These recommended solutions will then be reviewed in the MTEP and RTEP.[41]

b. <u>Regional Transmission Planning Cycles</u>

33. The MTEP follows an 18-month cycle, beginning in June of one year and ending in December the following year. The first six months of the MTEP process overlap with the final six months of the previous MTEP process.[42] Through the MTEP process, MISO identifies regional transmission needs and the transmission facilities that will be constructed to address those needs. After the MISO Board of Directors approves the MTEP, MISO holds a competitive bidding process to select transmission developers for eligible transmission projects.[43] The RTEP uses a 24-month cycle, made up of

[40] *Id.* § 9.3.5.2(a).

[41] *Id.* § 9.3.5.2(b).

[42] Midcontinent Indep. Sys. Operator, Inc., *MISO Transmission Expansion Plan 2015* (2015), p. 37, https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP15/MTEP15%20Full%20Report.pdf (MTEPIS Full Report). *See also* MISO, FERC Electric Tariff, Attachment FF, I.C.1 (43.0.0).

[43] MISO MTEP15 Full Report, pp. 50-51,

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two 12-month cycles for shorter lead-time projects (with a required in-service date 3-5 years in the future), and one 24-month cycle for longer lead-time projects (with a required in-service date more than five years in the future). Each of the three PJM processes begins in December of the relevant year.[44] As part of the RTEP process, PJM identifies transmission needs and opens proposal windows to solicit potential solutions to those needs. Over the 24-month transmission planning cycle, PJM holds two proposal windows for short lead-time solutions and a third proposal window for long lead-time solutions. PJM may also open a shortened proposal window for solutions to immediate reliability needs (those that need to be addressed in less than three years).[45] PJM recommends solutions to identified transmission needs and developers to construct those solutions to the PJM Board of Managers for approval.

c. <u>Complaint</u>

34. NIPSCO states that there are three fundamental problems related to transmission planning cycles and schedules in the JOA. First, there is no requirement for MISO and PJM to conduct a Coordinated System Plan Study. NIPSCO states that, at the time of its Complaint, MISO and PJM had not completed a Coordinated System Plan since 2008.[46] Second, the Coordinated System Plan Study process in the JOA is open-ended and does not stipulate any specific start or end time. NIPSCO states that the lack of deadlines in the JOA for completing a Coordinated System Plan Study means that the analysis does not have to be complete within a specific region's transmission planning cycle or even several cycles.[47] Third, the Coordinated System Plan Study in the JOA runs after, rather than concurrently with, the regional transmission planning processes, which causes significant delays.[48] NIPSCO asserts that an example of the negative consequences

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https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP15/MTEP15%20Full%20Report.pdf. *See also* MISO, FERC Electric Tariff, Attachment FF, I.C.1.b and VIII (43.0.0).

[44] PJM, Manual 14B: PJM Region Transmission Planning Process, at 14-18.

[45] PJM Interconnection, L.L.C., *RTEP Proposal Windows*, http://pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx.

[46] Complaint at 37.

[47] *Id.*

[48] *Id.* at 36-37.

caused by running the regional transmission planning processes and the Coordinated System Plan Study consecutively and not concurrently is its proposed Reynolds to Wilton Center project.[49] NIPSCO outlines the process the Reynolds to Wilton Center project followed and asserts that it demonstrates that it takes at least 42 months for a potential interregional economic transmission project to navigate the three independent processes, analyses, and approvals currently required under the JOA.[50] NIPSCO also asserts that the misalignment of the three economic study processes effectively precludes any interregional economic transmission project from ever being approved.[51]

35. NIPSCO asserts that the solution to these three fundamental problems is greater alignment between the MTEP, RTEP and Coordinated System Plan Study processes, and a requirement that the processes run concurrently. NIPSCO proposes a one-year, concurrent timeline, and asks that the Commission direct MISO and PJM to revise the JOA to implement its proposal. NIPSCO states that, under its proposal for concurrent processes, the regional transmission planning processes identify optimal solutions, the Coordinated System Plan Study in the JOA would evaluate for cross-border regional solutions, and finally, the regional processes and interregional analyses would be combined to determine what transmission projects should be approved.[52]

d. Comments Supporting Complaint[53]

36. NIPSCO again points to the example of its proposed Reynolds to Wilton Center project in its Complaint as illustrating the severity of the delays inherent in the three-process timeline.[54] In addition, NIPSCO asserts that over ten years of history have

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[49] NIPSCO states that this is a potential 345 kV transmission line from Reynolds (NIPSCO/MISO) to Wilton Center (Commonwealth Edison/PJM) that addressed PJM/MISO interregional issues within Northern Illinois and Northern Indiana. Complaint at 6.

[50] Complaint at 7.

[51] *Id.* at 38.

[52] *Id.* at 39-40 and Attachment A.

[53] We note that certain comments were summarized in the Technical Conference Order. *See* Technical Conference Order, 149 FERC ¶ 61,248 at PP 25-26.

[54] NIPSCO March 31, 2015 Pre-Technical Conference Comments at 5 (citing Complaint at 6-7, 37).

verified that no transmission developer has had the necessary foresight or fortitude to successfully run the gauntlet of the MISO-PJM interregional process. NIPSCO states that it therefore does not believe that it is possible for a transmission project to navigate all three existing processes.[55] NIPSCO argues that a timeline exceeding three years is unreasonably lengthy and denies consumers the benefits of efficient regional and interregional transmission planning, as NIPSCO asserts was required by Order Nos. 2000,[56] 890,[57] and 1000.[58] NIPSCO suggests that, if the three processes required by the JOA remain, the regional analyses performed by MISO and PJM should run concurrently with the interregional analysis under the JOA to determine the optimum planning solution. NIPSCO asserts that MISO and PJM agree with the need for "[b]etter alignment between regional and interregional processes," and urges the Commission to prescribe the interregional process that the RTOs should follow to achieve such alignment.[59]

37. NIPSCO also states that the proposed timeline provided in its Complaint, creating a one-year transmission planning process, would conform with the Commission's prior order recognizing that the MISO-PJM configuration separated a "highly interconnected" portion of the grid.[60] In addition, NIPSCO notes that that the most recent interregional

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[55] *Id.* at 7.

[56] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[57] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[58] NIPSCO March 31, 2015 Pre-Technical Conference Comments at 4-5.

[59] *Id.* at 5-8 (citing Midcontinent Indep. Sys. Operator, Inc. and PJM Interconnection, L.L.C., *MISO-PJM Cross-Border Planning*, Presentation at May 28, 2014 Joint and Common Market meeting, at 5, https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special)**.**

[60] NIPSCO July 15, 2015 Comments at 3 (citing Alliance Order, 103 FERC ¶ 61,274 at PP 26-27).

study process under the JOA took 39-42 months and produced zero transmission projects across this "highly interconnected" portion of the grid, and that the all-in timeline under the current process for a new transmission project could be as long as 10-12 years.[61]

38. NIPSCO contends that MISO and PJM staff at the technical conference fell back on the Order No. 1000 process, but overlooked the fact that the Commission has already recognized that the MISO-PJM seam, and NIPSCO's circumstances along that seam, are unique. NIPSCO asserts that, through a failure of proper planning, the current process pushes what should be transmission planning solutions into real-time problems and solutions. These real-time solutions, according to NIPSCO, are in turn resolved along the seam, with the impacts felt locally by NIPSCO's system and its load. NIPSCO argues that failure of the interregional transmission planning process in the JOA eventually forces these interregional economic transmission projects into the MTEP and RTEP as reliability projects, costs of which are typically borne by local customers.[62]

39. NIPSCO contends that its proposed reforms can be implemented without substantial modification to the RTOs' existing reliability transmission planning cycles and insists that the RTOs should be required to file a defined process for interregional transmission planning that runs concurrently with the regional transmission planning cycle on a defined and repeatable schedule.[63] NIPSCO reiterates that, as part of the last interregional study, MISO and PJM developed a schedule with defined deadlines, but because the deadlines were not contractually binding, the schedule slipped. NIPSCO contrasts this to the generator interconnection process, which it contends has been successful because of binding deadlines.[64] Accordingly, NIPSCO argues that the Commission should require the RTOs to file a defined process for interregional transmission planning that runs concurrently with the regional transmission planning cycle on a defined and repeatable schedule.[65]

40. NIPSCO proposes several specific tariff changes—or, in the alternative, a targeted settlement process—to address what it calls fundamental flaws of the existing transmission planning process:

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[61] *Id.* at 4.

[62] *Id.* at 4-5.

[63] *Id*. at 5-6.

[64] *Id*. at 6-7.

[65] *Id.* at 6.

- Section 9.3.6.1 of the JOA should be amended to include a requirement that a Coordinated System Plan be produced on an annual basis or some other specific timeframe determined by the Commission.

- Section 9.3.6.2 of the JOA should be amended to include a corresponding requirement that the underlying analyses be completed in a timely manner so that the final Coordinated System Plan is timely completed.

- The JOA should be amended to reflect the concurrent nature of the PJM, MISO, and joint planning cycles. Specifically, Section 9.3.6.1 should be amended to state: "[e]ach Party's annual transmission planning reports will be developed concurrently with the Coordinated System Plan," replacing the current language stating that "[e]ach Party's annual transmission planning reports will be incorporated into the Coordinated System Plan."

- Either Section 9.3.6.1 or 9.3.6.2 of the JOA should be amended to include the requirements proposed in Appendix A of NIPSCO's Complaint, such as the requirement that the RTOs "share project submittal lists" on a timely basis.[66]

41. In its comments, AWEA contends that, without a specific start or end date in the JOA, the interregional transmission planning process is ambiguous and open-ended, resulting in significant delays that impact the queuing of wind resources and transmission congestion.[67] Indiana Commission argues that requiring the MISO-PJM interregional transmission planning process to run concurrently with the MTEP and RTEP cycles will allow interregional economic transmission projects to be approved expeditiously, rather than waiting on another regional transmission planning cycle, which could lengthen the approval process by two years.[68]

42. Generator Group contends that NIPSCO's proposal for interregional transmission planning will have significant benefits, including: (1) alleviating delay that leads to increased costs to ratepayers; (2) addressing the lack of approved transmission; (3) incenting generation investment by signaling to generation developers that a robust grid is being maintained and planned, thereby alleviating their concerns about investing in new generation; (4) lowering retail rates for capacity, energy and ancillary services by allowing more optimal use of cost-effective generation; (5) enhancing grid reliability

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[66] NIPSCO August 14, 2015 Comments at 9-11.

[67] AWEA March 31, 2015 Pre-Technical Conference Comments at 2-3.

[68] Indiana Commission March 31, 2015 Pre-Technical Conference Comments at 3.

during an era of significant changes and challenges to the system; and (6) potentially encouraging regional rather than state-by-state implementation of the EPA's Clean Power Plan.[69] Generator Group states that the MTEP and the RTEP need to be revised to alleviate the mismatch between timing and study horizons. Generator Group also requests that the Commission direct MISO and PJM to demonstrate whether NIPSCO's proposed model to allow for concurrent review can work. In the alternative, Generator Group requests a targeted transition date where new, coordinated timelines for MTEP, RTEP and JOA planning are installed, so that MISO and PJM will be on identical internal timelines and will have identical milestones, which will facilitate eventual interregional review.[70]

43. Wisconsin Electric agrees with NIPSCO that the misalignment of the three economic study processes can have a negative impact on the likelihood of a transmission project being approved, and argues that the formal Coordinated System Plan Study would be more effective if specific deadlines were established to facilitate a better aligned, coordinated process. According to Wisconsin Electric, these deadlines should consider whether a transmission project can be implemented in the short-term (three to five years) or the long-term (more than five years). Wisconsin Electric suggests that a two-year common transmission planning process that performs both regional and interregional analysis of transmission issues at the beginning of the study process would enable a concurrent transmission planning cycle. Wisconsin Electric submits that it is appropriate to vary the length of the transmission planning cycle based on the urgency of the identified transmission issue and whether it involves a single issue (e.g., reliability, market efficiency, or public policy) or a combination thereof. Wisconsin Electric states that the coordinated transmission planning process for short-term transmission needs could follow a 12-month cycle and the study could be performed by an *ad hoc* study group under the direction of the Joint RTO Planning Committee. Wisconsin Electric suggests that an overlapping coordinated transmission planning process for long-term transmission needs could follow a 24-month cycle using a joint model with multiple future scenarios. Wisconsin Electric states that, while the length of each planning process may vary, there should be consistency in the general performance of the specific tasks for either study timeline.[71]

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[69] Generator Group March 31, 2015 Pre-Technical Conference Comments at 3-4.

[70] *Id.* at 4-6.

[71] Wisconsin Electric March 31, 2015 Pre-Technical Conference Comments at 2-6.

e. **Comments Opposing Complaint**

44. MISO agrees with NIPSCO that, to the extent possible, it would be appropriate for MISO and PJM to better align the MTEP and RTEP cycles and milestones, but notes that Order No. 1000 does not require that interregional and regional transmission planning processes be synchronized exactly, rather that they occur in "the same general timeframe." MISO contends that sequencing of some aspects of the regional and interregional transmission planning processes is unavoidable due to the requirement in Order No. 1000 that interregional transmission project proposals be submitted in the regional transmission planning processes before being considered in the interregional transmission planning process, and any transmission projects recommended by the interregional transmission planning process must be approved afterwards in the regional transmission planning processes.[72] MISO states that, while it is amenable to increasing coordination of the MTEP and RTEP schedules for interregional purposes, it may not be necessary to exactly align the regional transmission planning cycles to achieve that end.[73]

45. MISO and PJM state that their interregional and regional transmission planning cycles are highly aligned and that it is unnecessary to require them to run concurrently. To support this contention, MISO and PJM state that they conducted, after NIPSCO filed its Complaint, a joint coordinated planning study in 2014 (the "2012-2014 MISO-PJM Planning Study") that evaluated interregional transmission issues and identified opportunities for transmission expansion. MISO and PJM state that the 2012-2014 MISO-PJM Planning Study process ran concurrently with both the MTEP and the RTEP, which were situated to allow timely review of any interregional transmission projects that met the interregional and regional transmission planning criteria. MISO and PJM state that none of the 80 transmission projects they evaluated as part for the 2012-2014 MISO-PJM Planning Study process met all the necessary regional and interregional transmission planning criteria. However, MISO and PJM argue that this was not because of any mismatch in planning cycle timing and synchronization, but because no transmission projects met the cost-benefit thresholds.[74] MISO and PJM further argue that requiring the interregional and regional transmission planning processes to run simultaneously would significantly impair their ability to conduct important local and regional reliability

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[72] MISO October 31, 2013 Answer at 31-32 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 438-39; Order No. 1000-A, 139 FERC ¶ 61,132 at P 506).

[73] *Id.* at 33 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 436; Order No. 1000-A, 139 FERC ¶ 61,132 at P 506).

[74] MISO/PJM March 31, 2015 Pre-Technical Conference Joint Comments at 4-5.

work in a timely and efficient manner, because such a "mega-process" would encumber every regional transmission project with interregional requirements under the JOA.[75]

46. MISO and PJM state that some of NIPSCO's recommendations are beyond the requirements of Order No. 1000, and they do not believe more process is required or any revisions are necessary relative to the performance of the Coordinated System Plan Study process. MISO and PJM state that a process to conduct joint interregional transmission planning studies is already clearly spelled out in the JOA and it provides the RTOs and stakeholders the ability to determine when or if a joint study is appropriate.[76] MISO and PJM further state that the frequency of a Coordinated System Plan Study is based on whether (1) each RTO in the Joint RTO Planning Committee votes in favor of performing a Coordinated System Plan Study or (2) after two consecutive years during which a Coordinated System Plan Study has not been conducted and one RTO votes in favor of performing a Coordinated System Plan Study.[77]

47. MISO Transmission Owners, AEP and Exelon, and Xcel do not support the changes to the JOA that NIPSCO proposes.[78] MISO Transmission Owners argue that the Commission in Order No. 1000 dismissed suggestions of requiring a fixed timeframe within which transmission planning regions must jointly conduct interregional transmission planning processes.[79] AEP and Exelon state that it would be unrealistic to expect an RTO to alter regional transmission planning cycles to meet the interregional transmission planning needs of just one of its neighboring seams.[80] AEP and Exelon argue that it would be more productive for each RTO to first identify its own regional transmission needs through its regional transmission planning process and then come together through a joint interregional transmission planning process to determine if any interregional economic transmission projects can meet those regional transmission needs

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[75] *Id.* at 6-7.

[76] MISO/PJM August 14, 2015 Joint Comments at 5 (citing JOA § 9.3.5.1 and 9.3.5.2.).

[77] *Id.* at 5-6 (citing JOA § 9.3.5.2(a)(ii)).

[78] MISO Transmission Owners October 31, 2013 Comments at 7-8; AEP/Exelon March 31, 2015 Joint Comments at 5; Xcel March 31, 2015 Comments at 5-7.

[79] *Id.* (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 437, 439).

[80] AEP/Exelon March 31, 2015 Joint Comments at 5.

more efficiently and cost-effectively than any of the proposed regional transmission projects.

48. Xcel argues that the Complaint is fundamentally a request that the Commission order MISO and PJM to be considered one region for interregional transmission planning purposes. Xcel states that NIPSCO's suggested changes are not achievable given MISO's and PJM's separate regional transmission planning processes and that requiring MISO and PJM to effectively be considered one region for the purposes of interregional transmission planning could undermine the independent regional determinations necessary for successful regional transmission planning. Xcel asserts that, because the stakeholders in each region have different values, needs, and expectations, the focus should be the regional planning processes and the Commission should allow PJM and MISO to continue to improve their interregional planning processes through the stakeholder process.[81]

f. Reply Comments

49. NIPSCO disagrees with the RTOs' assertion that they have highly aligned interregional and regional planning cycles, noting that it would have taken at least 42 months, spanning multiple regional planning cycles of both RTOs, to study a single interregional transmission project. NIPSCO clarifies that its reforms would apply only to the MISO-PJM interregional transmission planning processes in the JOA and would not impact the regionally-specific processes that identify and mitigate issues driven by regional issues.[82] NIPSCO states that the RTOs do not address the problems created by overlapping yet non-synchronous transmission planning cycles detailed by NIPSCO. Further, NIPSCO states that the RTOs have not addressed the fact that the JOA does not specify a start or end date for a Coordinated System Plan Study, or even contain a requirement that such a plan be produced. NIPSCO notes again that the RTOs are capable of building a defined timeline that aligns with the regional planning cycles, and that they should use this defined timeline as a starting point for revising the JOA.[83]

50. In response to MISO's and PJM's argument that certain recommendations proposed by NIPSCO are beyond the requirements of Order No. 1000, ITC asserts that no interregional transmission project has been approved through the existing interregional process across the MISO-PJM seam and that this will continue unless the Commission

[81] Xcel March 31, 2015 Comments at 5-7.

[82] NIPSCO April 15, 2015 Reply Comments at 8-12.

[83] NIPSCO August 31, 2015 Reply Comments at 9-11.

implements reforms such as those proposed by NIPSCO and ITC. ITC adds that the Commission has previously recognized that the MISO-PJM seam is highly interconnected and explicitly conditioned the creation of the MISO-PJM seam pursuant to the provisions Order No. 2000 upon MISO and PJM and their stakeholders developing interregional coordination procedures. Similarly, ITC argues, in the instant proceeding the implementation of reforms such as those proposed by NIPSCO and ITC would be consistent with the interregional coordination requirements of Order No. 1000. Should the Commission find that the reforms proposed by NIPSCO and ITC exceed the scope of Order No. 1000, ITC supports NIPSCO's position that the Commission should go beyond the scope of Order No. 1000 to remedy the problems at the MISO-PJM seam.[84]

51. Generator Group supports the planning initiative proposed by Wisconsin Electric—a two-year common transmission planning process that performs both regional and interregional analysis of transmission issues on the front end of the study process—and states that the Commission should require MISO, PJM and the regional stakeholders to consider the merits of specific proposals such as this one.[85]

52. AEP and Exelon agree with MISO and PJM that Order No. 1000 did not require synchronized evaluation cycles for regional and interregional transmission planning, and that the timing and synchronization of the RTOs' respective regional transmission planning and their joint interregional transmission planning cycle were not the reasons why no interregional transmission projects were selected under the most recent joint coordinated planning study.[86]

53. PJM states that much time and effort went into PJM's and MISO's newly designed regional transmission planning cycles and argues that it and MISO should have the opportunity to complete a full planning cycle rather than being forced to abandon those changes before they are even fully tested. PJM further states that, while the Commission did not require PJM and MISO to produce a Coordinated System Plan annually, the JOA requires them to conduct an annual issue review administered by the Joint RTO Planning Committee to evaluate transmission issues, among other things. MISO and PJM state that, under the Coordinated System Plan Study process, the scheduling of the annual review must consider each RTO's planning cycle in order to provide meaningful opportunity for the review and use of such information. PJM argues that there is no point to require the RTOs to conduct an unnecessary study just for the sake of doing a study,

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[84] ITC April 15 Reply Comments at 2-4.

[85] Generator Group April 15, 2015 Reply Comments at 2-4.

[86] AEP/Exelon April 15, 2015 Reply Comments at 2-3.

and, since there are no disparities in the respective timing of the PJM and MISO regional study processes, interregional work necessarily proceeds concurrently with regional work. PJM states that the RTOs were fully aware of the differences between their regional processes and proposed revisions to the JOA to bake in the necessary flexibility to enable the coordination between the interregional and regional processes.[87]

g. Commission Determination

54. We grant the Complaint, in part, with regard to transmission planning cycles, and direct MISO and PJM to revise the JOA to include timely, specific deadlines for each step in the Coordinated System Plan Study process and a deadline for the maximum total amount of time the Coordinated System Plan Study process will take from the date the process begins to the date a Coordinated System Plan Study is approved. We direct MISO and PJM to revise the JOA to describe which and how specific steps in the Coordinated System Plan Study process interact and coordinate with specific steps in the MTEP and RTEP processes. Finally, as discussed below, we direct MISO and PJM to submit an informational filing that describes how MISO and PJM could potentially conduct the Coordinated System Plan Study concurrently with the MTEP and the RTEP. We also note that interregional transmission coordination will be examined at the technical conference to take place on June 27-28, 2016.[88]

55. We agree with NIPSCO that the existing open-ended process in the JOA that does not establish timely, specific deadlines for the Coordinated System Plan Study is unjust and unreasonable because it can lead to significant delays in the identification, analysis and potential approval of beneficial interregional economic transmission projects. For the same reason, as we discuss further below, we also find that MISO and PJM must revise the JOA to establish a deadline for the maximum total amount of time it will take to complete the full Coordinated System Plan Study process, including the annual review of transmission issues. These directives do not require MISO and PJM to change the Coordinated System Plan Study process or the annual review of transmission issues. Rather, MISO and PJM must create deadlines in the JOA for each step of the existing Coordinated System Plan Study process and specify the maximum amount of time that the total existing Coordinated System Plan Study process will take.

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[87] PJM September 3, 2015 Reply Comments at 7-8.

[88] *See* Notice of Technical Conference, Docket No. AD16-18-000 (2016). This technical conference will discuss issues related to competitive transmission development processes, including but not limited to use of cost containment provisions, the relationship of competitive transmission development to transmission incentives, and other ratemaking issues.

56. We also find that, based on the record in this proceeding, it is unclear how the Coordinated System Plan Study in the JOA interacts and aligns with the MTEP and the RTEP. Although MISO and PJM assert that the three processes are closely aligned, we find that JOA does not include language that explains this interaction in detail. The lack of a clear explanation in the JOA of the alignment of the Coordinated System Plan Study and the MTEP and RTEP processes has led to disagreements over whether and how the processes interact. For example, MISO and PJM assert that the processes are highly aligned and that it is unnecessary to require them to run concurrently,[89] while NIPSCO disputes that claim.[90] A clear process laid out in the JOA may resolve these disagreements and help provide a consistent understanding of the process for all stakeholders.

57. We agree with NIPSCO that the RTOs are capable of defining a timeline for the JOA that specifies the links to the MTEP and RTEP, and do not believe that the changes we are requiring of the RTOs are either unprecedented or unduly burdensome. We note that, in their joint comments, MISO and PJM state that the 2012-2014 MISO-PJM Planning Study process ran concurrently with both the MTEP and the RTEP.[91] Therefore, we direct MISO and PJM to submit, within 60 days of the date of this order, a compliance filing with revisions to the JOA to include (1) timely, specific binding deadlines for each step within the annual review of issues that lead up to the decision about whether or not to conduct a Coordinated System Plan; (2) an annual, binding deadline by which the RTOs will determine whether to conduct a Coordinated System Plan; (3)_timely, specific binding deadlines for each step in the Coordinated System Plan Study process once the RTOs decide to conduct that process; (4) a binding deadline for the maximum total amount of time the Coordinated System Plan Study process will take from the date the process begins to the date a Coordinated System Plan is approved; and (5) a description of which and how specific steps in the Coordinated System Plan Study process interact and coordinate with specific steps in the MTEP and the RTEP.

58. Based on the record in this proceeding, we deny NIPSCO's and Wisconsin Electric's request that the Commission require the MTEP, RTEP, and JOA processes to follow a common timeline or set of timelines with identical milestones and deadlines. However, in order to understand what specific changes might be necessary to allow all three processes to follow a common timeline, we require MISO and PJM to jointly study

[89] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 4.

[90] NIPSCO April 15, 2015 Reply Comments at 10.

[91] MISO/PJM March 31, 2015 Pre-Technical Conference Joint Comments at 4-5.

and report to the Commission, in an informational filing due within 120 days of the date of issuance of this order, how MISO and PJM could conduct the JOA transmission planning, MTEP and RTEP processes using a single, common timeline with identical milestones and deadlines. The informational filing should explain what specific impacts, if any, such changes would have on the regional transmission planning processes of MISO and PJM and on the interregional coordination MISO and PJM conduct with other neighboring transmission planning regions.

59. We also deny NIPSCO's request to require MISO and PJM to conduct a Coordinated System Plan Study on a regular basis, or include new provisions in the JOA specifying explicit start and end dates for conducting a regular Coordinated System Plan Study. We agree with PJM that it is appropriate for a Coordinated System Plan Study to be conducted when such a study is found to be necessary based on the RTOs' annual review of transmission issues. Furthermore, requiring a Coordinated System Plan Study on a regular basis, even when the RTOs' annual review of transmission issues finds it unnecessary, would not be an efficient use of MISO's, PJM's, and stakeholders' time and resources. If NIPSCO or other stakeholders believe that there are transmission issues that warrant a Coordinated System Plan Study, they are able to advocate for that position in the open and transparent stakeholder process mandated under the JOA.

60. We also find that our requirement for the JOA to specifically describe how steps in the Coordinated System Plan Study process schedule interact and coordinate with specific steps in each of the two regional processes will help all stakeholders reach a common understanding of how the three processes inform and interact with each other. Increasing stakeholder understanding of the Coordinated System Plan Study process through development of timely, specific deadlines, and an explanation of the interaction with the MTEP and the RTEP could improve coordination of the regional and interregional transmission planning processes, and reduce various risks, such as planning and financing risks, associated with developing interregional transmission projects, thereby increasing the likelihood that any such projects can successfully navigate the study and approval process and ultimately get built.

2. Modeling and Criteria

a. JOA

61. With regard to modeling and criteria, the JOA requires MISO and PJM to exchange specific data and information on an annual basis in support of interregional transmission planning coordination, including power flow models for projected system conditions for the transmission planning horizon (up to the next 10 years) that include planned generation development and retirements, planned transmission facilities and

seasonal load projections, system stability models, production cost models, and the underlying assumptions and contingency lists used in those models.[92] The JOA also states that the models will be consistent with those used in each RTO's transmission planning processes.[93] In addition, the JOA states that, upon request, other data and information as is needed for each RTO to plan its own system accurately and reliably is provided and so each RTO can assess the impact of conditions existing on the system of the other RTO.[94]

62. The JOA also outlines that MISO and PJM engage in their own, single party transmission planning activities including expansion plans, system impact studies, and generator interconnection studies. MISO and PJM share information that arises in the performance of this single party planning as is necessary for effective coordination between MISO and PJM, including generators permanently retiring or suspending operations and proposed transmission enhancements.[95]

63. With regard to the Coordinated System Plan Study process, MISO and PJM will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system.[96] Specifically, the JOA states that the purpose of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability and is an integral part of the expansion plans of each RTO.[97] The Coordinated System Plan integrates the RTOs' respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation or merchant transmission) and Network Upgrades identified jointly by the RTOs and sets forth actions to resolve any impacts that may result across the seams between the RTOs' systems due to such integration.[98]

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[92] JOA § 9.2.1.

[93] *Id.*

[94] *Id.* § 9.2.2.

[95] *Id.* § 9.3.1.

[96] *Id.* § 9.3.2.

[97] *Id.*.

[98] *Id.* § 9.3.5.1.

64. According to the JOA, the Joint RTO Planning Committee develops an initial scope and procedure for the coordinated planning analysis, which includes evaluations of issues resulting from the annual coordinated review and analysis of each RTO's transmission issues. The JOA then outlines that MISO and PJM will document the scope and assumptions for the conduct of the Coordinated System Plan Study. The scope design will include the evaluation of the transmission system against the reliability criteria, operational performance criteria, economic performance criteria, and public policy needs applicable to each RTO. Specifically, MISO and PJM use joint study planning models that the Joint RTO Planning Committee develops, which are consistent with the models and assumptions used for the most recently completed or currently underway MTEP and RTEP. The JOA also states that if the Coordinated System Plan Study requires transmission evaluations driven by different regional needs, then the coordination of studies, models, and assumptions will include the analyses appropriate to each region. The JOA outlines that MISO and PJM 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.[99] Also, the JOA states that the Interregional Planning Stakeholder Advisory Committee will have the opportunity to provide feedback to the Joint RTO Planning Committee regarding the study models and in the development of potential solutions; however, the Joint RTO Planning Committee is responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as an interregional transmission project.[100]

b. <u>Complaint</u>

65. NIPSCO argues that there should be consistency between the MISO and PJM planning analyses, and that while the RTOs have regional differences, both entities should be consistent in their application of reliability criteria and modeling assumptions. NIPSCO requests that the Commission mandate MISO and PJM to develop and utilize a single combined MISO-PJM regional transmission planning model for annual reliability and economic planning related to interregional transmission issues so that the RTOs use the same modeling assumptions (electric system topology and generation dispatch) in any interregional transmission planning studies. NIPSCO states that commonality between the regional models should translate into commonality in the interregional model. NIPSCO reasons that the use of a common model will eliminate duplication and lead to a

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[99] *Id.* § 9.3.5.2(b)(vi).

[100] *Id.* § 9.3.5.2(b)(vii).

more realistic modeling system topology/dispatch that will reflect the system conditions anticipated in the operating horizon. NIPSCO states that simply exchanging data and then using two separate models, studied independently, can lead to inconsistent outcomes and result in a failure to properly identify potential reliability issues. Additionally, NIPSCO states that the RTOs should perform joint analysis for all issues along the seams. NIPSCO also states that the Commission should stipulate timelines associated with development of this common model.[101]

66. On a more specific level, NIPSCO states that the RTOs' regional economic models should contain the same topology and the same (or highly similar) resource and load assumptions, including growth rates for resources and load, for the MISO and PJM footprints that would result in targeting areas where inefficiencies exist both regionally and interregionally.[102] NIPSCO also states that a joint, common model for regional reliability planning studies should be used, which would include base-line reliability, generator interconnection, generator retirements, transmission service requests, and Auction Revenue Rights requests.[103]

67. NIPSCO maintains that the Commission should require alignment of the planning assumptions and provide a specific date for the RTOs' filing in this regard.[104] NIPSCO asserts that the Commission should direct MISO and PJM to amend the JOA to eliminate disconnects that occur interregionally when combining two differing regional processes, including benchmarking their interregional model to actual system operation. NIPSCO recounts that these regional differences tend to obscure the way the system along the seam is modeled and planned compared to the way it is operated.[105]

68. Finally, NIPSCO requests that until such time as MISO and PJM produce joint models for seams related studies, MISO and PJM should be required to be consistent in their application of each RTO's reliability and economic assumptions and criteria. NIPSCO states that, for example, when PJM is studying a PJM generator interconnection request for possible impacts on the MISO system, PJM should use the MISO criteria applicable to the potentially impacted MISO facilities instead of PJM criteria, and vice-

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[101] Complaint at 7-8, 42.

[102] NIPSCO March 31, 2015 Pre-Technical Conference Comments at 9.

[103] *Id.* at 10; Complaint at 27.

[104] NIPSCO July 15, 2015 Comments at 8.

[105] NIPSCO August 14, 2015 Comments at 8.

versa. Otherwise, according to NIPSCO, one RTO could miss a potential problem on the other RTO's transmission system.[106]

c. Comments Supporting Complaint

69. ATC, ITC, AWEA, Generator Group and Indiana Commission support the use of a single, joint model. Specifically, commenters state that the Commission should require MISO and PJM to develop and use a single, joint model that uses the same assumptions, metrics, and future scenarios in the cross-border transmission planning process to identify and evaluate interregional transmission projects.[107] AWEA and Generator Group also support a uniform use of reliability criteria and modeling assumptions until a new single model is put in place.[108] AWEA states that a joint model should include a common single combined MTEP/RTEP with common load, generator dispatch, and other core assumptions for use in the cross-border transmission planning process. In addition, AWEA states that the joint model should more realistically reflect congestion seen in the day-ahead and real-time markets and achieve commonality between the regional models. AWEA also acknowledges that MISO and PJM currently produce a single model to use in evaluating interregional economic transmission projects through the Interregional Planning Stakeholder Advisory Committee; however, AWEA states that there is still work to be done in improving the development of this joint model and for greater alignment between each region's intraregional modeling.[109]

70. Southern Indiana states that the current, single Interregional Planning Stakeholder Advisory Committee interregional economic transmission project process is a good first step in developing such a joint, common model. However, Southern Indiana states that the Interregional Planning Stakeholder Advisory Committee process requires additional improvements in congestion modeling, common resource and load assumptions

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[106] *Id.* at 8.

[107] ATC March 30, 2015 Pre-Technical Conference Comments at 4; AWEA March 31, 2015 Pre-Technical Conference Comments at 3; ITC March 31, 2015 Pre-Technical Conference Comments at 5; NIPSCO March 31, 2015 Pre-Technical Conference Comments at 8; Indiana Commission March 31, 2015 Pre-Technical Conference Comments at 3-4; Generator Group March 31, 2015 Pre-Technical Conference Comments at 6; Southern Indiana March 31, 2015 Comments at 3.

[108] AWEA March 31, 2015 Pre-Technical Conference Comments at 3; Generator Group March 31, 2015 Pre-Technical Conference Comments at 6.

[109] AWEA March 31, 2015 Pre-Technical Conference Comments at 3-4.

(including projected growth rates) before it can serve as a firm foundation for the development of such a model. Southern Indiana states that the use of a common model would ensure common assumptions and projections of baseline reliability, generator interconnections, generator retirements, and transmission service requests, which, in turn, would allow issues to be identified and addressed in planning processes, reducing the need to deal with these issues in real-time operations.[110]

71. ITC recognizes that MISO and PJM have made some progress toward developing a joint model that uses the same assumptions in the interregional transmission planning process since the time that NIPSCO filed the Complaint, as the RTOs did develop a joint model during the inaugural Coordinated System Plan Study. ITC argues that the benefits associated with MISO and PJM's use of a joint model were, however, diminished by the fact that the two RTOs were unable to agree on all aspects of the model, including how to evaluate the benefits of potential transmission projects using various future scenarios. ITC states that it is vitally important that MISO and PJM agree on all aspects of the joint model, including any assumptions, metrics, and scenarios.[111] ATC agrees that the Joint RTO Planning Committee should use common models and a common set of criteria during the subsequent interregional transmission planning process to evaluate possible interregional transmission facilities.[112] Similarly, Indiana Commission supports a single model.[113]

72. AEP and Exelon argue for the elimination of the interregional transmission study process for determining reliability needs in favor of each RTO using its regional study process to determine its regional reliability needs. However, AEP and Exelon state that when running their respective regional reliability studies, each RTO should study facilities that are located in the neighboring RTO footprint to ensure that all reliability impacts on both RTO footprints caused by each RTO's planning criteria are identified and addressed. Similarly, AEP and Exelon state that each RTO should also model similar testing conditions in the other RTO footprint when conducting reliability testing of its own regional facilities. AEP and Exelon state that this should ensure that unrealistic testing discontinuities are not created across the seam. Finally, AEP and Exelon state that

[110] Southern Indiana March 31, 2015 Pre-Technical Conference Comments at 3.

[111] ITC March 31, 2015 Pre-Technical Conference Comments at 5.

[112] ATC March 30, 2015 Pre-Technical Conference Comments at 4.

[113] Indiana Commission March 31, 2015 Pre-Technical Conference Comments at 3-4.

reliability upgrades that are physically located entirely within one RTO footprint that eliminate the need for reliability upgrades that are physically located entirely within the other RTO footprint should also be considered during the planning process.[114]

73. Generator Group notes that each RTO has different methods and thresholds for modelling criteria and assumptions for baseline reliability analyses, Network Resource Interconnection Studies, Energy Resource Interconnection Studies, generator interconnection studies, and generator retirement studies.[115] Generator Group argues that MISO and PJM need to apply the same standards so project developers can accurately assess data provided in studies, because when a proposed transmission project impacts the seam, it is very difficult for a generation developer to evaluate data in MISO and PJM-provided studies and to independently assess the market when MISO and PJM do not apply the same standards.[116] Additionally, Generator Group states that the Commission should look to harmonize the actual dispatch that is used in modeling. Generator Group states that insofar as the seam is concerned, actual dispatch data should be compared to determine whether MISO and PJM should employ the same dispatch assumptions since dispatch assumptions that differ from actual can exacerbate congestion at the seam.[117] Generator Group states that MISO and PJM also model previously queued generator projects, active in the Definitive Planning Phase, and projects in suspension, differently.[118]

74. With regard to identifying constraints and flowgates, Generator Group states that the two RTOs apparently apply different definitions (i.e., "tests") to identify constrained facilities and flowgates, which Generator Group says results in large variances in the number of identified constrained transmission facilities. Generator Group states that chronic congestion at the seam has thus not resulted in transmission solutions and that the two RTOs do not see or model the seams landscape in the same way. Generator Group also suggests that the Commission require MISO to address whether it agrees with the results of PJM's application of MISO's test and why MISO has not proposed a

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[114] AEP/Exelon March 31, 2015 Pre-Technical Conference Comments at 10-11.

[115] Generator Group March 31, 2015 Pre-Technical Conference Comments at 6-12.

[116] *Id.* at 7-9.

[117] *Id.* at 10-11; Generator Group August 14, 2015 Comments at 7.

[118] Generator Group March 31, 2015 Pre-Technical Conference Comments at 13.

transmission solution for each limiting facility and flowgate. Generator Group states that this divergence shows there is a need for a single model that uses similar assumptions.[119]

75. Generator Group states that MISO and PJM should be required to include all transmission facilities that are affected by congestion caused by the neighboring RTO even if not all facilities individually meet the threshold to be identified as a constrained transmission facility (i.e. identified as a market-to-market flowgate). Generator Group states that properly defined flowgates and constraints are a must if the benefits of a joint and common market are to be realized. Generator Group states that the current constructs have not been shown to properly define and identify constraints for the MISO-PJM region. Instead, Generator Group states that properly defined and identified constraints and flowgates could lead to transmission solutions, which in turn would reduce the cost of energy and market-to-market payments, lead to a more stable and reliable grid, and incentivize the generation development community to invest in new generation.[120]

76. Generator Group states that panelists at the technical conference drew a distinction between reliability needs and operational needs, and they contended addressing reliability needs is not an issue; however, Generator Group disagrees. Generator Group states that one of the drivers of the failure to maintain a robust grid at the seam is the difference in how MISO and PJM apply NERC reliability criteria. Generator Group believes that PJM applies NERC criteria in a way that tends to require the most robust grid, but MISO does the opposite. Generator Group states that this mismatch contributes to system congestion and an under-developed grid.[121]

77. With respect to study horizons, Generator Group comments that MISO's most recent July Planning Advisory Committee meeting, transmission owners within MISO stated they opposed a move to the five-year model. Generator Group believes this issue remains at a stalemate, but that there is a need to eliminate the mismatch of MISO looking ten years out and PJM looking five years out.[122]

[119] *Id.* at 13-14.

[120] *Id.* at 14-15.

[121] Generator Group August 14, 2015 Comments at 3-4.

[122] *Id.* at 4-5.

d. Comments Opposing Complaint

78. MISO and PJM state that they have structured their regional and interregional transmission planning processes to achieve a single model and common assumptions for use in the Coordinated System Plan Study. Specifically, MISO and PJM state that commencing in 2012 and ending in 2014, the RTOs used a single model that applied the same assumptions in a joint coordinated planning study that evaluated cross-border transmission issues and identified opportunities for transmission expansion. With regard to NIPSCO's proposal to require consistency between the MISO and PJM planning analyses, MISO contends that while Order No. 1000 requires that regional data and models be harmonized, it does not require that they be identical. MISO states that under existing practices, MISO already coordinates its model development with PJM and updates the PJM representation in its models based on feedback received. MISO states that going forward, the mandated exchange of modeling data on an annual basis under Order No. 1000 will ensure that parties to the JOA will have the most up-to-date representation of the neighboring region's transmission system in the models used for regional transmission planning. MISO states that it intends to use the models it receives from PJM to represent PJM's regional transmission system (including topology, generation dispatch, generation projections, and load forecasts) for purposes of interregional coordination and planning.[123]

79. MISO states that it is willing to consider potential improvements in the consistency of the analysis and modeling performed pursuant to the JOA. In addition, to the extent the issues raised in the Complaint relate more to the appropriate implementation of the JOA, MISO states that such implementation matters should be addressed through the JOA's own coordination mechanisms, including the Interregional Planning Stakeholder Advisory Committee's interregional stakeholder process. Moreover, MISO states that collateral estoppel precludes challenges to Order No. 1000's requirement that an interregional process be significantly derived from regional analyses, including the application of reliability criteria and modeling assumptions.[124]

80. MISO and PJM state that for their regional transmission planning processes, the RTOs use the most recent available model of the neighboring RTO's system. MISO and PJM explain that under their Order No. 1000 interregional compliance filings, the RTOs committed to exchange reliability and economic models on an annual basis to use them to develop a common model for interregional transmission studies. MISO and PJM state

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[123] MISO October 31, 2013 Comments at 34.

[124] *Id.* at 34-35.

that they also proposed JOA revisions explaining that known updates will be factored into study models that will be available for stakeholder review.[125] MISO and PJM reiterate that they already have developed and currently use a single model that applies common assumptions to an interregional study. MISO and PJM state that given that the Order No. 1000 revisions were accepted by the Commission in the MISO-PJM First Interregional Compliance Order, the RTOs should not be forced to abandon such efforts before being given an opportunity to apply the revisions intended to apply the single model and common assumptions for use in the Coordinated System Plan Study.[126]

81. MISO Transmission Owners and Xcel contend that requiring consistency between the MISO and PJM planning process and requiring that MISO and PJM to effectively be considered one region in the interregional economic transmission project planning process is not required and that the JOA, as revised in the Order No. 1000 interregional compliance filings, continues to be just and reasonable. MISO Transmission Owners and Xcel note that the Commission stated in Order No. 1000 that it would leave to each pair of neighboring regions discretion in the way the procedure for joint evaluation requirement is designed and implemented and would not require that any particular planning horizons or criteria be used.[127] Further, MISO Transmission Owners are concerned that the modifications NIPSCO requests could give PJM a say in MISO's independent regional determinations and analysis (and *vice versa*).[128] MISO Transmission Owners believe that the JOA permits consideration of the information identified by NIPSCO in the Complaint, and if the existing process is failing, such failure should be addressed through a process that involves the stakeholders.[129]

82. Similarly, Xcel believes the Commission should allow MISO and PJM to continue to improve their interregional transmission planning processes under the JOA through the stakeholder process. Xcel explains the processes in place under the JOA that strive for modeling commonalities. Xcel believes the details of interregional transmission planning should remain at the RTO level, as the RTOs and their stakeholder communities are the

[125] JOA, § 9.3.5.2(b)(vi).

[126] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 7-8.

[127] MISO Transmission Owners October 31, 2013 Comments at 8; Xcel March 31, 2015 Pre-Technical Conference Comments at 6-7 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 437).

[128] MISO Transmission Owners October 31, 2013 Comments at 8-9.

[129] *Id.* at 9.

experts on the various intricacies of their respective areas. Xcel states that instead of focusing on regional modeling assumptions with the interregional transmission planning process, the Commission should allow MISO and PJM to continue to coordinate regional transmission plans through data exchange. Xcel further states that it does not believe the lack of interregional economic transmission projects to date is necessarily a result of the difference between the models used in MISO and PJM.[130]

83. AEP and Exelon, Xcel, and PSEG Companies note that each RTO has different modeling practices and assumptions in its regional transmission planning criteria that were specifically developed to address that RTO's unique regional needs.[131] PSEG Companies also argue the planning model for each RTO reflects variations in preferences and assumptions about resources that are specific to each RTO and its stakeholder body.[132] AEP and Exelon and PSEG Companies state that given these differences, and the regional reasons for these differences, it is unrealistic and impractical to expect that both RTOs will change their respective regional transmission planning criteria, models and practices to accommodate their joint seam, which is not the only seam each RTO has with its neighbors.[133] PSEG Companies conclude that the existence of different modeling approaches is consistent with the Commission's recognition for regional differences under Order No. 1000.[134]

e. <u>Reply Comments</u>

84. In response to the RTOs and AEP and Exelon, NIPSCO argues that it is important to distinguish the regional differences that reflect composition of a system, longstanding operational and contractual practices, and differences that are choices regarding input into a model. NIPSCO states that the MISO-PJM seam pulls apart a highly interconnected portion of the transmission grid and requires a much greater degree of cooperation and

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[130] Xcel March 31, 2015 Pre-Technical Conference Comments at 7.

[131] AEP/Exelon March 31, 2015 Pre-Technical Conference Comments at 6-7; Xcel March 31, 2015 Pre-Technical Conference Comments at 6; PSEG Companies July 15, 2015 Comments at 2.

[132] PSEG Companies July 15, 2015 Comments at 2.

[133] AEP/Exelon March 31, 2015 Comments at 6-7; PSEG Companies July 15, 2015 Comments at 3.

[134] PSEG Companies July 15, 2015 Comments at 2 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 61).

consistency. NIPSCO states that although MISO and PJM produce a single model to use in evaluating interregional economic transmission projects through the Interregional Planning Stakeholder Advisory Committee, they have not developed joint models for regional reliability modeling. NIPSCO continues to point out that important differences remain between MISO and PJM in terms of how the single model for interregional economic transmission project is built compared to the regional models, the lack of benchmarking to actual system issues, and how the Coordinated System Plan Study is performed and evaluated.[135]

85. Generator Group comments that not only are the modeling assumptions different in each RTO, but MISO and PJM apparently do not model each other's system the same way. Moreover, Generator Group states that NIPSCO submitted comments showing other disparities, and Generator Group submits that if an interregional transmission project is ever to be built, a single model with similar assumptions should be required.[136]

86. In response to NIPSCO, PJM states that Order No. 1000 required interregional transmission coordination, not interregional transmission planning. PJM notes that the Commission acknowledged in Order No. 1000 that coordination would be required to effectuate the Commission's acceptance of regional differences. PJM states that the RTOs made revisions to the JOA in their respective Order No. 1000 dockets to improve coordination between the seams.[137] For instance, PJM states that the JOA was revised to provide for greater opportunities for data and information exchange, including power flow models, system stability models, production cost models, and assumptions used in the development of those models.[138] PJM also states that the revisions to the Coordinated System Plan Study process provide the RTOs the opportunity to perform more exhaustive benchmark review of such models.[139]

87. In response to PJM's arguments that Order No. 1000 required interregional transmission coordination, not interregional transmission planning, NIPSCO states that it

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[135] NIPSCO April 14, 2015 Reply Comments at 13-14.

[136] Generator Group April 15, 2015 Reply Comments at 5.

[137] PJM September 3, 2015 Reply Comments at 4.

[138] *Id.* at 4 (citing JOA, § 9.2).

[139] *Id.* at 3-4.

has repeatedly reiterated in this proceeding why the MISO-PJM seam is unique, and the Commission has acknowledged the unique nature of this seam.[140]

f. Commission Determination

88. We deny NIPSCO's Complaint with regard to modeling and criteria. As we discuss below, we find that the JOA already requires MISO and PJM to use a joint model with the same assumptions for reliability and economic planning when they conduct interregional planning under the JOA. However, MISO and PJM do not use a joint model with the same assumptions and criteria for the reliability and economic planning each RTO conducts as part of its own regional transmission planning, pursuant to its individual tariff. Given the concerns present along the MISO-PJM seam, we find that, as discussed further below, MISO and PJM should explore the potential use of a joint model with the same assumptions and criteria and submit informational report on this issue to the Commission.

89. With respect to the interregional transmission planning, the JOA already requires an annual exchange of data between the RTOs[141] as well as a process to conduct the Coordinated System Plan Study, which includes compromises on assumptions and a joint model for transmission expansion planning.[142] Additionally, we find that the JOA outlines a process for MISO and PJM to develop common assumptions for the Coordinated System Plan Study. MISO and PJM must then document the scope and assumptions, including the process and schedule for the conduct of the Coordinated System Plan Study.[143] We also note that, if a particular Coordinated System Plan Study process is meant to address different regional needs, then the studies, models, and assumptions will include the analyses appropriate to address the region-specific needs. Moreover, we also note that the JOA requires that known updates and revisions to models be incorporated in a comprehensive fashion when new base planning models are available.[144]

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[140] NIPSCO September 28 Limited Answer at 5 (citing Technical Conference Order, 149 FERC ¶ 61,248 at P 35).

[141] JOA, § 9.2.1.

[142] *Id.* § 9.3.2.

[143] *Id.* § 9.3.5.2(b)(v).

[144] *Id.* § 9.3.5.2(b)(v-vi).

90. In addition, the existing Coordinated System Plan Study process under the JOA already requires the use of a joint study model that is consistent with the models and assumptions used for the MTEP and RTEP cycles most recently completed or under development for each region.[145] In addition, MISO and PJM must develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be accommodated.[146] As such, the joint model will reflect common load level assumptions, generation dispatch, and system topology and the study sensitivities will address any differing regional assumptions. The JOA also requires MISO and PJM to use a joint interregional study model with a single set of common assumptions[147] and provides stakeholders with an opportunity to provide comments on the joint model and the common assumptions.[148]

91. With regard to commenters' arguments that MISO and PJM should be consistent in their application of each RTO's reliability and economic assumptions and criteria, we find that the JOA already has data exchange procedures in place such that each RTO is able to accurately capture the reliability and economic assumptions and criteria of the other RTO's system.[149] Indeed, MISO and PJM state that for their regional transmission planning processes, the RTOs use the most recent available model of the neighboring RTO's system.[150] We also note that within the single party planning provisions of the JOA, the RTOs agree to share, on an ongoing basis, information when they individually perform such single party planning activities so that they are effectively coordinating between themselves and so that they can identify proposed transmission system enhancements that may affect the RTOs' respective systems.[151]

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[145] *Id.* § 9.3.5.2(b)(vi).

[146] *Id.*

[147] *Id.* § 9.3.5.2(b)(ii-vi).

[148] *Id.* § 9.3.5.2(b)(ii, vii).

[149] JOA § 9.2.1.

[150] MISO/PJM March 31, 2015 Comments at 7.

[151] JOA § 9.3.1.

92. We note that commenters argue that many of the underlying issues are occurring because the MTEP and RTEP use different assumptions and criteria.[152] Specifically, with respect to commenters' request that the MTEP and RTEP use the same models and assumptions, we find that, based on the record in this proceeding, it is not appropriate at this time to require MISO and PJM to change their respective regional transmission planning criteria and practices. We understand that the regional transmission planning models for each RTO were designed to reflect variations in preferences and assumptions about resources that are specific to each RTO and its stakeholders. We also note that the coordination and data exchange in place within the JOA are designed to address how conflicts in the application and modeling of regional criteria, assumptions, solutions, and modeling will be resolved. However, we agree with commenters that argue that many issues along the MISO-PJM seam might be more easily identified and resolved if MISO and PJM did use a joint model with the same assumptions and criteria when conducting regional transmission planning. Therefore, we direct MISO and PJM to jointly explore through the stakeholder process the potential use of a joint model with the same assumptions and criteria in their regional transmission planning processes. We also direct MISO and PJM to submit, within 180 days of the date of issuance of this order, an informational report describing how MISO and PJM could implement a joint model with the same assumptions and criteria in their regional transmission planning processes.

93. Some commenters also suggest that some transmission planning models the RTOs use in baseline reliability analyses, generator interconnection, generator retirement studies, Network Resource Interconnection Studies, and Energy Resource Interconnection Studies do not use realistic dispatch assumptions.[153] While there may be potential changes that could improve how joint and regional models reflect congestion in the day-ahead and real-time markets, commenters have not demonstrated that the existing dispatch assumptions lead to unjust and unreasonable results. However, to the extent there are potential improvements that could be implemented and agreed upon, we encourage the stakeholder process to address these issues. For example, we understand that there are current efforts to improve metrics and processes within the Interregional

[152] This issue is brought up by commenters in the context of baseline reliability studies, generator interconnection studies, generator retirement studies, transmission service requests, NRIS studies, ERIS studies, and Auction Revenue Rights requests.

[153] NIPSCO March 31, 2015 Pre-Technical Conference Comments at 10; Southern Indiana March 31, 2015 Pre-Technical Conference Comments at 3; Generator Group March 31, 2015 Pre-Technical Conference Comments at 6-12.

Planning Stakeholder Advisory Committee, and we encourage those efforts to continue.[154]

94. With regard to Generator Group's contention that MISO and PJM need to better identify constraints and flowgates, not use an outdated definition of flowgate, and should include consideration of all flowgates that cause congestion, not just those that meet the market-to-market tests; we note that the currently-effective JOA contains the processes the RTOs use to establish agreed-upon flowgates for which they will monitor congestion and jointly dispatch their systems when the flowgates are constrained and either party initiates the market-to-market process.[155] In any event, this issue was not raised in the Complaint and, as such, goes beyond the scope of the Complaint.

3. Cost Allocation and Lower Voltage Transmission

a. Currently Effective Cost Allocation Criteria and Methods

95. To qualify as a interregional economic transmission project under the JOA, a transmission project must: (1) have an estimated cost of $20 million or greater;[156] (2) be evaluated as part of a Coordinated System Plan Study or joint study process; (3) meet a 1.25 to 1 benefit to cost ratio, calculated using the method outlined in the JOA;[157] (4) qualify as an economic transmission enhancement or expansion under the terms of the PJM RTEP[158] and as a Market Efficiency Project[159] under the terms of the MISO tariff,

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[154] MISO and PJM began discussing some of these issues within the Interregional Planning Stakeholder Advisory Committee in the third quarter of 2015.

[155] *See* JOA, Attachment 3, § 1.

[156] On December 2, 2015, in Docket Nos. ER16-488-000 and ER16-490-000, MISO and PJM submitted a filing to the Commission proposing to remove the $20 million threshold in the JOA. On February 5, 2016, the Commission approved the proposal with an effective date of February 8, 2016. *See PJM Interconnection, L.L.C.*, 154 FERC ¶ 61,083 (2016).

[157] JOA, § 9.4.4.1.2.1.

[158] An Economic-based Enhancement or Expansion shall be included in the RTEP recommended to the PJM Board, if the relative benefits and costs of the Economic-based Enhancement or Expansion meet a benefit to cost ratio threshold of at least 1.25:1. *See* PJM, Intra-PJM Tariffs, OATT, Operating Agreement, Schedule 6.1, § 1.5.7(d)(4.0.0).

[159] Market Efficiency Projects are defined as:

(continued ...)

among other things;[160] and (5) address one or more constraints for which at least one dispatchable generator in the adjacent market has a Generation-to-Load Distribution Factor of five percent or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.[161]

96. The table below summarizes the three sets of thresholds (MISO's, PJM's and the JOA's) that a transmission project must meet to qualify as an interregional economic transmission project under the JOA.

> Network Upgrades: (i) that are proposed by the Transmission Provider, Transmission Owner(s), ITC(s), Market Participant(s), or regulatory authorities; (ii) that are found to be eligible for inclusion in the [MTEP] or are approved pursuant to…the [MISO Transmission Owners Agreement]…; (iii) that have a Project Cost of $5 million or more; (iv) that involve facilities with voltages of 345 kV or higher; and that may include any lower voltage facilities of 100 kV or above that collectively constitute less than fifty percent (50%) of the combined project cost, and without which the 345 kV or higher facilities could not deliver sufficient benefit to meet the required [1.25] benefit-to-cost ratio threshold…; (v) that are not determined to be Multi Value Projects; and (vi) that are found to have regional benefits under…Attachment FF.

MISO, FERC Electric Tariff, Attachment FF, § II.B (43.0.0).

[160] Any minimum project cost threshold required to qualify as the relevant transmission project under either the PJM tariff or MISO tariff shall apply the total project cost of the interregional economic transmission project and not the allocated cost. *See* JOA, § 9.4.4.1.2.iv.

[161] *See* JOA, § 9.4.4.1.2.

Interregional Market Efficiency Project Threshold			
	MISO-PJM JOA[162]	**MISO Regional Thresholds**[163]	**PJM Regional Thresholds**[164]
Cost	No Minimum	\$5 million	No Minimum
Voltage	No Minimum	≥345 kV	>100kV
Cost/Benefit Ratio	1/1.25	1/1.25	1/1.25
Benefit Calculation Used for Cost/Benefit Ratio	70% adjusted production costs (APC) / 30% net load payment (NLP)	100% APC	50% APC / 50% NLP

b. <u>Complaint</u>

97. NIPSCO states that an interregional economic transmission project must navigate three separate and significantly different processes and their applicable criteria: (1) the MTEP regional process and criteria; (2) the RTEP process and criteria; and (3) the joint interregional process and criteria as specified in the JOA. NIPSCO asserts that the requirement to pass all three, divergent criteria (the "triple hurdle") provides an unjust

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[162] *See* JOA, § 9.4.4.1.2 and § 9.4.4.1.2.1.

[163] *See* MISO, FERC Electric Tariff, Attachment FF, § II.B (Market Efficiency Projects) and MISO, FERC Electric Tariff, Attachment FF, § II.B.1 (Criteria to Determine Whether a Project Should be Included as a Market Efficiency Project) (43.0.0).

[164] *See* PJM, Intra-PJM Tariffs, OATT, Schedule 12, § (b)(v) (Economic Projects) (6.1.0).

and unreasonable impediment to finding the most cost effective solution for customers.[165] NIPSCO requests, therefore, that the Commission require MISO and PJM to develop a single, jointly agreed upon set of interregional criteria instead of the current three sets of criteria required by the JOA.[166] As evidence that this change is needed, NIPSCO argues that to date, no MISO-PJM interregional economic transmission project has met all three sets of criteria.[167]

c. Comments Supporting Complaint

98. AEP, ATC, AWEA, E.ON, Exelon, Generator Group, Hoosier Wind, Indiana Commission, Indiana Consumer Counsel, ITC, Southern Indiana, PSEG Companies, and Wisconsin Electric generally support NIPSCO's proposal to reform the criteria and benefits metrics for interregional economic transmission projects. Generator Group states that there are benefits to be achieved from moving to uniform criteria to evaluate interregional economic transmission projects because the current process and criteria are too restrictive.[168] Indiana Commission supports the use of a single common set of criteria to evaluate interregional economic transmission projects because it believes that it would serve to expedite cross-border transmission planning and the ultimate approval of projects.[169] Specifically, Indiana Commission supports a change in the interregional economic transmission project criteria to include projects lower than 345 kV and below the $20 million threshold, which will provide the RTOs with flexibility in identifying the most cost-effective solutions.[170] ITC agrees with NIPSCO that the current JOA process creates a series of insurmountable hurdles to the approval of beneficial interregional projects—such as requiring projects to meet three distinct sets of criteria to be approved as interregional projects. ITC therefore recommends that once an interregional economic transmission project is approved pursuant to the provisions of the JOA, MISO and PJM should automatically recommend the project for approval in their respective regional

[165] Complaint at 44.

[166] *Id.* at 46.

[167] *Id.* at 44.

[168] Generator Group March 31, 2015 Pre-Technical Conference Comments at 15-16.

[169] Indiana Commission March 31, 2015 Pre-Technical Conference Comments at 4; Indiana Commission July 15 Comments at 2-3.

[170] Indiana Commission July 15 Comments at 2-3.

transmission plans for purposes of regional cost allocation.[171] Southern Indiana states that the proposed regional solutions should be evaluated only on the individual region's criteria because the three existing study processes have precluded the approval of any proposed interregional economic transmission project.[172]

99. With respect to how the benefits metrics and benefit to cost ratio are calculated and performed, NIPSCO proposes to change the formulation of Adjusted Production Cost in the JOA. NIPSCO argues that the value of exports and imports for areas within each RTO should be counted at the zonal level,[173] not just exports and imports at the RTO-wide level. Furthermore, NIPSCO argues that curtailed or infeasible Auction Revenue Rights/Long-Term Transmission Rights allocation should be taken into account instead of using the current assumption that all internal generation to load within an RTO is fully hedged. NIPSCO also proposes, among other things, to change the Net Load Payment benefit calculation by eliminating the phrase "the estimated value of congestion hedging transmission rights."[174]

100. AWEA, Generator Group, E.ON, Hoosier Wind, Indiana Commission, ITC and Southern Indiana generally support NIPSCO's proposal to change the voltage and cost thresholds. Generator Group believes that based on the data gathered from the RTOs' Quick Hit Analysis,[175] there is a need to study the benefits of lowering the threshold to 100 kV. According to Generator Group, NIPSCO's proposed 100 kV threshold in the Complaint is reasonable and is consistent with the voltage threshold under NERC standards for determining facilities that impact the bulk electric system.[176] ITC maintains that the current voltage and minimum project cost thresholds arbitrarily limit the projects that are considered, as demonstrated by the fact that a project could potentially qualify in each RTO as a regional transmission project for cost allocation but be excluded in the

[171] ITC March 31, 2015 Pre-Technical Conference Comments at 6-7.

[172] Southern Indiana March 31, 2015 Pre-Technical Conference Comments at 2-3.

[173] According to NIPSCO, these transactions are subject to market-to-market payments and are not fully hedged. NIPSCO August 14, 2015 Comments at 13.

[174] NIPSCO August 14, 2015 Comments at 13-15.

[175] The Quick Hit Analysis is an effort by MISO, PJM and its stakeholders to identify near-term interregional economic transmission projects to remedy recent historical interregional congestion issues. *See infra* P 108.

[176] Generator Group March 31, 2015 Pre-Technical Conference Comments at 20.

interregional process.[177] Hoosier Wind advocates for 69 kV and above.[178] Southern Indiana agrees with NIPSCO that MISO and PJM should have a process for joint planning and cost allocation of lower voltage and lower cost interregional economic transmission projects.[179] ATC argues that including lower voltage projects in the interregional transmission planning process will streamline the process by allowing for evaluation of a project that would otherwise be overlooked as a cost-effective and more efficient solution.[180]

101. As an alternative, AEP and Exelon propose a process whereby both the interregional study process for determining and quantifying regional market efficiency needs and for determining reliability needs should be eliminated in favor of each RTO using its respective and established regional study process to determine and quantify its respective regional market efficiency needs and its regional reliability needs.[181] AEP and Exelon state that the Interregional Planning Stakeholder Advisory Committee continues to explore potential revisions to the interregional transmission planning process and stakeholder discussions have been robust. AEP and Exelon request that the Commission refrain from directing specific planning revisions through this proceeding and instead allow the stakeholder process to continue until the end of the year. However, they suggest that the Commission provide a clear timeline within which the stakeholders of both RTO's must work on possible revisions to the process.[182]

102. ITC disagrees with AEP and Exelon's suggestion that the regional criteria of each RTO should be used in the interregional transmission planning process because it believes that each RTO uses different metrics in its respective regional transmission planning processes to measure the benefits associated with particular projects as well as the benefits associated with a potential interregional transmission project. As a result, the appropriate cost allocation for a particular interregional transmission project, which is based on the benefits of the project to each RTO, would not be clear. ITC further notes

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[177] ITC March 31, 2015 Pre-Technical Conference Comments at 8; ITC July 15, 2015 Comments at 1, 4, 6-7; ITC August 14, 2015 Comments at 4-5, 10.

[178] Hoosier Wind October 31, 2013 Comments at 7-9.

[179] Southern Indiana March 31, 2015 Pre-Technical Conference Comments at 4.

[180] ATC March 30, 2015 Pre-Technical Conference Comments at 4.

[181] AEP/Exelon March 31, 2015 Pre-Technical Conference Comments at 7-8.

[182] AEP/Exelon August 14, 2015 Comments at 4.

that such uncertainty will lead to disputes over cost allocation and will continue to preclude necessary interregional projects from being built. Accordingly, ITC posits the only path forward is to create one set of interregional criteria that will clearly determine the benefits of a particular project to each RTO.[183] ITC states that it is only aware of two projects that qualified as interregional economic transmission projects under the MISO-PJM interregional transmission planning criteria with benefit/cost ratios of 1.84 and 2.15, respectively, but which were not approved as interregional transmission projects because they did not meet MISO's regional Market Efficiency Project requirement of a minimum voltage of 345 kV. Accordingly, ITC submits this is a result of the design of the JOA planning process and interregional cost allocation framework, which recognizes only a single type of benefit per transmission project and ignores a host of additional benefits a project may provide. ITC believes that the Commission should direct MISO and PJM to create an interregional process which aligns interregional and regional project criteria in a single, separate interregional project category contained in both the regional and interregional transmission planning processes.[184]

103. PSEG Companies add that each region should, at a minimum, be allowed to retain its respective thresholds for clearing an interregional transmission project because each region, consistent with the regional differences recognized by the Commission, values different types of projects differently. For instance, one RTO might value wind resources while the other RTO values natural gas resources and solar, such that retaining each RTO's approval criteria will appropriately allow recognition of each region's supply and public policy preferences.[185]

104. NIPSCO states that a change to the thresholds should be adopted because lower voltage and lower cost transmission projects will help the RTOs achieve the most cost-effective solutions for customers consistent with Order No. 1000 and earlier orders. NIPSCO argues that the RTOs have no plans to make any changes to the JOA or individual RTO tariffs.[186] NIPSCO continues to argue that lower voltage transmission projects provide interregional benefits. For example, NIPSCO states that the 138 kV Michigan to LaPorte transmission project provides approximately $62 million of congestion relief, of which $58.2 million of the benefit is to PJM. However, because the

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[183] *Id*. at 3.

[184] ITC August 14, 2015 Comments at 4-6.

[185] PSEG Companies July 15, 2015 Comments at 3-4.

[186] NIPSCO March 31, 2015 Pre-Technical Conference Comments at 25-26.

Michigan to LaPorte transmission project is a 138 kV transmission line, in cannot meet the 345 kV threshold under MISO's tariff.

105. NIPSCO argues that although MISO testified that MISO is "not necessarily opposed" to changing the voltage criteria as they relate to the PJM seam, MISO's representative noted that a significant majority of the stakeholders are opposed to the change. NIPSCO argues that such a change to MISO's cost allocation method(s) must therefore occur on compliance from a Commission order.[187] Generator Group adds that no progress has been made to lower the voltage threshold for interregional transmission projects in the MTEP.[188]

d. Comments Opposing Complaint

106. MISO and PJM argue that the tiered criteria embodied in the JOA were developed in recognition of the principle that transmission projects should benefit both regions if they are to be built and their costs shared between the two regions' customers. MISO and PJM state that the JOA also recognizes the reality that states may be reluctant to site transmission projects that cross their state but provide few benefits to their customers. In addition, MISO and PJM note that states may be reluctant to site transmission produced by or that are based on assumptions that may be inconsistent with assumptions adopted by stakeholders in their transmission planning region.[189] MISO and PJM note that neither the JOA nor the RTEP include a voltage limitation for consideration of interregional economic transmission projects. However, MISO states that it has previously discussed with its stakeholders the possibility of modifying the 345 kV Market Efficiency Project voltage threshold that is a requirement for such a project to be selected in the MTEP, but no consensus has been reached on such a change.[190] MISO and PJM maintain, however, that the individual regional analyses are a necessary component of the

[187] NIPSCO July 15, 2015 Comments at 15-16.

[188] Generator Group August 14, 2015 Comments at 2-3.

[189] MISO and PJM argue that requiring a single criterion regardless of the regions' determination of benefits to each region would require a fundamental rethinking by the Commission of Order No. 1000 criteria which: (1) allows one region to veto projects that traverse their region and do not benefit them; and (2) holds that interregional plans flow from regional plans by examining regional plans for more efficient or cost-effective alternatives. *See* MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 8-9.

[190] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 12.

interregional study process to ensure that an interregional transmission project is a more efficient or cost effective solution to a regional issue. They claim that, without the regional reviews, they would not be able to determine whether or not the interregional transmission projects addresses regional needs or how it would compare as an alternative to a proposed regional solution.[191]

107. Nevertheless, both RTOs agree that it may be appropriate to lower the JOA's project cost thresholds,[192] and they agree that further examination of the criteria for transmission projects qualifying as interregional transmission projects should be explored. Accordingly, MISO and PJM state that they have been working on incremental improvements to the criteria set forth in the JOA. MISO and PJM explain that beginning in late 2014 after the completion of the MISO-PJM Joint Planning Study, the RTOs conducted an extensive fact-finding analysis. MISO and PJM also state that they are committed to work through the Interregional Planning Stakeholder Advisory Committee to improve interregional study metrics and processes, starting with a metrics and process review.[193] However, they believe that these potential changes are interregional coordination issues that should be addressed through the Interregional Planning Stakeholder Advisory Committee.[194] MISO and PJM state that they are committed to work with their stakeholders to review the process and metrics for interregional economic projects such as, but not limited to, how the benefits metrics are calculated and how the cost/benefit test is performed.[195]

108. MISO and PJM explain that in an effort to identify potential interregional economic transmission projects, they initiated the Quick Hit Analysis to identify near-term interregional transmission projects to remedy recent historical interregional congestion issues. MISO and PJM state that, more specifically, the Quick Hit Analysis was conducted to identify near-term economic upgrades, and includes transmission projects that may not otherwise meet the cost and voltage thresholds of interregional economic transmission projects and/or MISO's regional Market Efficiency Project

[191] MISO/PJM August 14, 2015 Pre-Technical Conference Comments at 6.

[192] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 12.

[193] *Id*. at 9.

[194] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 12.

[195] MISO/PJM August 14, 2015 Pre-Technical Conference Comments at 6.

criteria. The Quick Hit Analysis identified approximately 40 transmission projects.[196] MISO and PJM state that they continue to review the results with stakeholders and, importantly, to discuss how to allocate the costs of these projects.[197] MISO and PJM state that many of the transmission upgrades in the Quick Hit Analysis were relatively small in scope, lower voltage facilities and well below the $20 million threshold required by the JOA. In order for these transmission projects to be included as interregional economic transmission projects, the JOA would have to be revised to reduce the $20 million threshold.[198] Thus, MISO and PJM propose to lower or eliminate the $20 million cost threshold for interregional market efficiency projects.

109. In addition, MISO and PJM state that while there is no voltage threshold in the JOA, the MISO tariff limits regional cost allocation of Market Efficiency Projects to 345 kV and above. MISO commits to review the applicability of these regional criteria through its stakeholder process beginning in the fourth quarter of 2015, and will provide an update to the Commission on the progress beginning at the end of the first quarter of 2016.[199] MISO and PJM state that many of the transmission projects identified in the Quick Hit Analysis included transmission projects below $5 million and voltages as low as 69 kV. In addition, MISO commits to review the applicability of its cost allocation

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[196] A majority of the identified Quick Hit projects are rated below 345 kV (i.e., 138 or 161 kV) and with a cost below $20 million. *See* MISO-PJM IPSAC Meeting, *Quick Hit Study* (Mar. 17, 2015), http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/ipsac-midwest.aspx. *See also* MISO-PJM Interregional Planning Stakeholder Advisory Committee Meeting, *Quick Hit Analysis Executive Summary* (Apr. 14, 2015), http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/ipsac-midwest.aspx.

[197] *See* MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 11, n.24.

[198] *See* MISO/PJM August 14, 2015 Comments at 3-4.

[199] On March 31, 2016, MISO submitted an answer to provide an update on the status of the stakeholder process. MISO states that it proposed a timetable for the stakeholder process, including a milestone goal of December 2016 for establishing a conceptual proposal, a subsequent period for additional stakeholder review, and a goal of filing no later than 2018. *See* MISO March 31, 2016 Answer at 5. NIPSCO asks the Commission to reject this process and instead provide specific solutions to address issues along the MISO-PJM seam based on the record in this proceeding. *See* NIPSCO April 8 Answer at 3.

thresholds to interregional economic transmission projects through the MISO stakeholder process beginning in the 4th quarter of 2015 and commits to provide an update to the Commission on the progress beginning at the end of the 1st quarter of 2016.[200]

110. Xcel believes that NIPSCO's Complaint is a request for the Commission to order MISO and PJM to be considered one region for interregional transmission planning purposes, which Xcel argues could undermine the independent regional determinations necessary for successful MTEP and RTEP planning. Xcel asserts that stakeholders in each region have differing values, needs, and expectations that are difficult to combine into a single planning process.[201] Xcel does not support a requirement to relax or modify existing cost allocation and/or benefits criteria for the interregional economic transmission projects. Xcel opposes any reduction of the 345 kV threshold as it believes the voltage requirement is neither unreasonable nor an impediment to the development of projects lower than 345 kV that provide significant economic benefits.[202]

111. MISO Transmission Owners do not oppose using common criteria, but state that it would be a long-term goal best suited for the RTO stakeholder processes to ensure that proposed reforms do not violate Order No. 1000 and other Commission policies.[203] With respect to lower voltage transmission projects, MISO Transmission Owners note that both MISO and PJM stakeholders rejected such a proposal leading up to the submission of the Order No. 1000 interregional compliance filings and that NIPSCO's proposal should be rejected as unnecessary and contrary to stakeholders' intent.[204]

e. <u>Reply Comments/Answers</u>

112. In response to MISO and PJM's assertion that interregional coordination issues should be addressed in the Interregional Planning Stakeholder Advisory Committee, NIPSCO states that there must be some reasonable limit on the extent to which the

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[200] *See* MISO/PJM August 14, 2015 Comments at 3-4.

[201] Xcel March 31, 2015 Pre-Technical Conference Comments at 5-6.

[202] *Id.* at 8-9.

[203] MISO Transmission Owners October 31, 2013 Comments at 9-10.

[204] *Id.* at 12-13.

stakeholder process can provide meaningful reform. NIPSCO notes that stakeholders present their commercial interests, not the public interest.[205]

113. In reply to AEP and Exelon's suggestion that their proposed joint planning process would identify the most efficient and cost-effective solutions, irrespective of their voltage rating, NIPSCO states that it has discussed at length in prior pleadings the potential value that lower cost and lower voltage projects can deliver. In particular, NIPSCO believes that these lower voltage facilities work in tandem with higher voltage facilities in the transmission network to provide a path for both RTOs to move their economic power to the rest of their respective footprints. NIPSCO reasons that having one of these lower voltage facilities limiting the transfer capability of the higher voltage facilities is inefficient and should not be ignored just because of a regionally specific decision of MISO's stakeholders.[206]

114. AEP and Exelon disagree with Xcel's argument that the regional voltage and project cost criteria should not be changed for joint transmission planning and cost allocation. AEP and Exelon state that MISO and PJM have shown that "no upgrade below 345 kV or upgrade with installed costs estimated at less than $20 Million would be able to gain final approvals in both regions." AEP and Exelon appreciate ITC's recommendation to lower the thresholds for interregional projects from $20 million to $5 million and the voltage threshold to 100kV. However, even with a $5 million threshold, the problem remains that there is no guarantee that local transmission owners will make the upgrades themselves.[207]

115. Generator Group opposes the suggestion that further discussions should occur through the MISO stakeholder process and instead urge the reform through this docket. Generator Group states that it provided information with its initial comments demonstrating that the MISO stakeholder process considered this issue and it was rejected. Accordingly, Generator Group concludes that the MISO stakeholder process will not bring about the reform that is needed.[208] Generator Group disagrees with Xcel's contention that the voltage floor is not "an impediment to the development of projects lower than 345 kV."[209] Generator Group also argues that the Commission should reject

[205] NIPSCO April 15, 2015 Reply Comments at 16.

[206] *Id.* at 21.

[207] AEP/Exelon April 15, 2015 Reply Comments at 6-10.

[208] *Id.* at 1-2.

[209] *Id.* at 12-13.

AEP and Exelon's proposal to eliminate the interregional study process for reliability projects.[210]

116. AEP and Exelon maintain that NIPSCO's suggestion to eliminate the regional screens for interregional transmission planning and only using the interregional metrics is neither feasible nor required by Order No. 1000. AEP and Exelon state that in Order No. 1000, the Commission explained that each transmission planning region "has unique characteristics and, therefore, this Final Rule accords transmission planning regions significant flexibility to tailor regional transmission planning and cost allocation processes to accommodate these regional differences."[211] As such, AEP and Exelon suggest that the Commission should reject NIPSCO's proposal and state that a more pragmatic approach to eliminating the "three hurdle" burden would be to keep the regional metrics and eliminate the interregional metrics.[212] AEP and Exelon agree with MISO and PJM that having a single set of interregional criteria that is dramatically different from regional criteria will lead to reluctance by the states to site transmission in their state.[213]

117. ITC disagrees with MISO and PJM that a single, unified interregional project category precludes consideration of those interregional transmission projects in each regional transmission planning process.[214] ITC also argues that AEP and Exelon's recommendation to eliminate the interregional study process for determining and quantifying regional market efficiency needs and for determining reliability needs will fail to consider the full range of interregional transmission project benefits on an additive basis and will block otherwise beneficial projects due to differences in regional criteria and project categorization.[215]

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[210] *Id.* at 4-5.

[211] AEP/Exelon August 31, 2015 Reply Comments at 2 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 61).

[212] *Id*. at 3.

[213] AEP/Exelon April 15, 2015 Reply Comments at 5.

[214] ITC August 31, 2015 Reply Comments at 2.

[215] *Id*. at 3.

118. With respect to NIPSCO's preference to use one set of interregional test, rather than three separate tests, and to eliminate the assumption that all "internal RTO" transactions are fully hedged, PJM objects to this change as it would force each region to accept projects without any analysis confirming that the project addresses regional needs. Furthermore, PJM notes that without first identifying regional needs, an interregional transmission project could not be found to be a more efficient or cost effective solution to address a regional need (because there is no regional need to compare it to) and thus would make it impossible to determine whether each region benefits and to what degree. PJM also contends that NIPSCO's proposed changes to the benefits metrics in the JOA should be rejected. PJM argues that these new issues are being raised for the first time by NIPSCO in this docket rather than the stakeholder forum. PJM maintains that all stakeholders, not just NIPSCO, should have the opportunity to thoroughly review proposals that may affect their market position in order to evaluate the proposal and agree upon such changes.[216]

119. Generator Group supports the Quick Hit Analysis and recommends that the JOA, MISO tariff, and/or PJM tariff be revised in order to allow a voltage threshold down to 69 kV and dollar threshold to $5 million for interregional transmission projects.[217] NIPSCO adds that it does not support a separate process in the JOA to conduct future Quick Hit Analyses, but that MISO and PJM should be required to lower the voltage and cost thresholds.[218] PJM states that it supports lowering the voltage and cost thresholds.[219] PJM adds that the results of the Quick Hit study showed, among other things, that congestion on lower voltage facilities could be resolved with low cost incremental upgrades (i.e., upgrades costing less than $5 million).[220]

120. In response to Exelon's argument that the Commission should refrain from directing specific planning revisions and instead allow the stakeholder process to continue, Generator Group asserts that the Commission should not let the MISO stakeholder process run its course unchecked. Generator Group observes that MISO has stated its support for numerous changes to remove barriers to the development of interregional economic transmission projects in MISO and under the JOA. According to

[216] *Id*. at 10-11.

[217] Generator Group August 31, 2015 Reply Comments at 8-9.

[218] NIPSCO August 31, 2015 Reply Comments at 7-8, 9, 20.

[219] PJM September 3, 2015 Reply Comments at 11-12.

[220] *Id.* at 4.

Generator Group, this indicates that MISO's current tariff is impeding the development of such projects and that the Commission must act. Generator Group therefore urges the Commission to impose December 1, 2016 as the deadline for MISO to file tariff revisions to resolve the cost allocation and voltage threshold issues raised in the Complaint.[221]

121. Noting that the Generator Group relies on the MISO Whitepaper in support of its assertion that MISO supports changes to remove barriers to market efficiency projects, Xcel argues that such reliance is misplaced because the purpose of the MISO Whitepaper is to identify potential issues that MISO should evaluate before any tariff changes are made.[222]

122. Xcel also argues that it is both procedurally improper and premature for the Commission to impose a December 1, 2016 deadline for MISO to submit tariff changes as requested by Generator Group. Xcel states that the record in this proceeding is insufficient to support the changes desired by the Generator Group, and requiring a change with no supporting analysis would likely result in unintended consequences and potentially, unjust and unreasonable cost allocations and resulting transmission rates. Further, Xcel states that the Commission has not found the current MISO cost allocation process unjust and unreasonable and has not ordered MISO to change from the currently approved cost allocation process. According to Xcel, the Commission should allow MISO, along with its neighboring RTOs and stakeholders, to continue to assess appropriate regional and interregional cost allocation methodologies.[223]

123. MISO Transmission Owners state that while they do not take a position with respect to the underlying issues, they oppose any attempt to impose a hard deadline on the stakeholder process. MISO Transmission Owners therefore assert that the Commission should reject Generator Group's request for a December 1, 2016 deadline by which MISO must file tariff revisions revising criteria for evaluating market efficiency projects.[224]

[221] Generator Group February 3, 2016 Answer/Supplemental Comments at 4-10 (citing MISO, *Cost Allocation Issues Whitepaper* (Sept. 14, 2015, Revised Nov. 9, 2015), https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RECBTF/2015/20151112/20151118%20RECBTF%20Item%20XX%20Cost%20Allocation%20Issue%20Summary%20Paper%20clean.pdf) (MISO Whitepaper).

[222] Xcel February 18, 2016 Answer at 4-6.

[223] *Id.* at 6-9.

[224] MISO Transmission Owners February 22, 2016 Answer at 4-6.

124. Generator Group states that while it understands the value of a stakeholder process, that process has not resulted in solutions in this instance after years of discussion. According to Generator Group, MISO tariff revisions are necessary to develop necessary transmission facilities, and setting a deadline is the most effective means for producing those revisions. Generator Group maintains that the MISO Whitepaper identifies the need for, and potential benefits from, revised interregional economic transmission project criteria.[225] Although Generator Group states that it agrees that analysis of cost allocation methodologies is necessary, Generator Group argues that it should not be allowed to proceed without end.[226]

125. Generator Group disagrees with Xcel's argument that the imposition of a deadline is premature because, according to Generator Group, the record in this proceeding demonstrates that market efficiency project criteria have inhibited and continue to inhibit the development of new transmission in MISO and as interregional economic transmission projects under the JOA. With respect to MISO Transmission Owners' argument that the deadline may inhibit analysis and discussion in the stakeholder process, Generator Group argues that MISO Transmission Owners have not explained how this would happen. According to Generator Group, the deadline will ensure that such analysis and discussion will take place on a timely basis. Generator Group observes that MISO did not file in opposition to Generator Group's deadline request or state that the deadline will inhibit discussion and analysis.[227]

126. Generator Group disagrees with Xcel's argument that the record is insufficient in this proceeding to support the changes identified by the Generator Group. According to Generator Group, the specific changes – lower the interregional economic transmission project voltage level, expand the interregional economic transmission project benefits definition and change the MEP benefits/cost ratio – are well-known and documented. Generator Group asserts that it is not advocating any specific outcome, but has rather only requested a deadline by when whatever outcome is decided is filed at the Commission. Generator Group adds that the Commission has previously imposed a

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[225] Generator Group February 29, 2016 Answer at 3 (citing MISO Whitepaper).

[226] *Id.* at 2-3.

[227] *Id.* at 3-4.

similar deadline in MISO regarding transmission cost allocation issues, and MISO and the MISO stakeholders responded and met that deadline.[228]

127. In response to PJM's arguments regarding Quick Hit projects, NIPSCO asserts that PJM has no answer for the missing half of the Quick Hit study equation: cost allocation. According to NIPSCO, the fundamental flaw with the Quick Hit study process is that there is no cost allocation plan included in the tariffs and agreements that properly allocates cost to load within both PJM and MISO based on relative benefits. NIPSCO argues that the Quick Hit process does not exist in any tariff or the JOA and flies in the face of Order No. 1000.[229]

128. In response to NIPSCO's arguments regarding the Quick His Analysis, PJM states that it would not be productive to address cost allocation for projects identified under a Quick Hit Analysis until the threshold requirements for interregional market efficiency projects under the JOA are either reduced or eliminated. PJM maintains that many of the upgrades identified under the Quick Hit Analysis were not able to satisfy the interregional economic transmission project criteria under the JOA because they are below the requisite estimated project cost threshold of $20 million and cannot satisfy the 345 kV threshold to qualify as a market efficiency project under MISO's tariff. PJM argues that, contrary to NIPSCO's assertions, the ability of the RTOs to build projects identified under the Quick Hit study process is not dependent upon the RTOs developing a cost allocation methodology, but rather is much more dependent upon first reducing or eliminating (i) the $20 million cost threshold for interregional market efficiency projects in the JOA[230] and (ii) the voltage threshold in MISO's regional tariff. PJM states that reducing or eliminating the project cost and voltage threshold would enable projects identified under the Quick Hit study process to satisfy the criteria to qualify as an interregional economic transmission project for purposes of cost allocation under the JOA.[231]

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[228] *Id.* at 4-5 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060 (2009) (according to Generator Group, that deadline led to MISO's submission of its MVP transmission criteria to build new transmission)).

[229] NIPSCO September 28 Limited Answer at 4-6.

[230] As noted above, the $20 million cost threshold for interregional market efficiency projects in the JOA was subsequently eliminated. *See supra* n.156.

[231] PJM October 13 Answer at 2-3.

f. Commission Determination

129. We grant in part and deny in part the Complaint. We find that NIPSCO has demonstrated that certain provisions of the JOA and MISO tariff are unjust, unreasonable, or unduly discriminatory or preferential pursuant to section 206 of the FPA because the current cost and voltage thresholds prohibit from consideration certain transmission projects in the MISO-PJM interregional transmission planning process that benefit both regions, as evidenced by the Quick Hit Analysis. Therefore, as discussed further below, we require MISO to reduce its minimum voltage threshold for a interregional economic transmission project from 345 kV to 100 kV. In addition, we require MISO to eliminate the $5 million cost threshold for interregional economic transmission projects. Finally, we require MISO and PJM to remove the requirement in the JOA to conduct a third, separate benefit-cost analysis for the combined MISO and PJM regions.

130. As a threshold issue, we reject NIPSCO's request that the JOA requirement that an interregional economic transmission project qualify as both an economic transmission project under the PJM tariff and as a Market Efficiency Project under the MISO tariff be replaced with a single set of interregional criteria and a single benefit calculation. We find that replacing both sets of regional criteria and benefit calculations would not recognize that MISO and PJM have separate regional transmission planning processes and that each region should be able to evaluate a potential interregional economic transmission project to ensure it provides sufficient benefits to its region. However, we find that two of MISO's regional Market Efficiency Project thresholds are unjust and unreasonable when applied to interregional economic transmission projects.

131. Specifically, we agree with NIPSCO that certain aspects of the identified "triple hurdle" prevent interregional economic transmission projects from being evaluated in the interregional transmission planning process. Importantly, we agree with NIPSCO and commenters that the Quick Hit Analysis has validated that many identified interregional economic transmission projects that are less than 345 kV and cost less $5 million may nevertheless provide benefits to each region and should therefore not be automatically excluded from consideration.[232] We find that a majority of the identified Quick Hit projects are rated below 345 kV (i.e., 138/161 kV) and cost less than $5 million (with several costing only several hundred thousand dollars).[233] In fact, the Quick Hit Analysis

[232] *See, e.g.*, NIPSCO July 15, 2015 Comments at 15-16; ITC Companies August 14, 2015 Comments at 8.

[233] *See* MISO/PJM August 14, 2015 Comments at 4.

identified interregional economic transmission upgrades (1) below $1 million and (2) 138 kV and above with significant economic benefits to both RTOs.[234] In their post-technical conference comments, MISO and PJM concede that cost and voltage thresholds would need to be "addressed" in order to approve the identified solutions from the Quick Hit Analysis.[235] While MISO and PJM state that they continue to review the results with stakeholders, we find that there is sufficient evidence from the Quick Hit Analysis[236] to demonstrate that MISO and PJM must remove the thresholds that are preventing them from being able to select the interregional economic transmission projects that they have identified as providing benefits to both regions.[237] We therefore direct MISO to submit, within 60 days of the date of issuance of this order, a filing to revise its tariff to remove the requirement that an interregional economic transmission project must be at least 345 kV and cost at least $5 million. Specifically, MISO must revise its tariff to revise the Market Efficiency Project thresholds that apply to qualify as an interregional economic transmission project by (1) lowering the minimum voltage threshold to 100 kV and (2) removing the $5 million minimum cost requirement. This will allow an interregional economic transmission project above 100 kV to qualify as a Market Efficiency Project regardless of its cost so long as it meets the other requirements, including MISO's regional cost benefit threshold.[238]

132. MISO and PJM also identified several transmission projects in the Quick Hit Analysis that will relieve congestion and benefit both MISO and PJM, but did not meet the 1.25 benefit-to-cost ratio for the combined region under the JOA.[239] We find it is

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[234] *See id.*

[235] *See id.* at 3-4.

[236] *See supra* P 108, n. 196; *see also, e.g.*, MISO/PJM August 14, 2015 Comments at 3-4.

[237] *See* MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 11, n.24.

[238] We are not requiring MISO to change the Market Efficiency Project 345 kV and $5 million dollar minimum thresholds for MISO regional transmission projects (i.e., regional transmission projects that are not interregional economic transmission projects under the JOA must still meet those thresholds to qualify as Market Efficiency Projects).

[239] *See, e.g.*, MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 19; AEP/Exelon August 14, 2015 Comments at 5.

unjust and unreasonable that an interregional economic transmission project that MISO and PJM each find provides sufficient benefits to its individual region to be rejected because a separate interregional cost-benefit analysis calculated differently than either RTO's analysis cannot be met. While MISO and PJM concede that "[s]everal [Quick Hit Projects] relieved congestion and showed benefit to both MISO and PJM, but did not meet the 1.25 benefit-to-cost ratio threshold[]",[240] we find that MISO and PJM fail to explain or otherwise justify why the use of a separate interregional benefit-cost analysis, calculated differently than either of their individual benefit-cost analysis, continues to be just and reasonable when each region must still find that an interregional economic transmission project provides sufficient benefits to meet the regional benefit-cost analysis. We therefore direct MISO and PJM to submit, within 60 days of the date of issuance of this order, a filing to revise section 9.4.4.1.2.1 (Determination of Benefits to Each RTO from an Interregional Market Efficiency Project) of the JOA to remove the requirement that an interregional economic transmission project meet a 1.25-to-1 benefit-to-cost ratio for the combined MISO-PJM regions in addition to having to meet a 1.25-to-1 benefit-to-cost ratio for both MISO and PJM separately.

133. We also direct MISO and PJM to revise section 9.4.4.2.2 (Cost Allocation for an Interregional Market Efficiency Project), as follows:

> For [interregional economic transmission projects] that meet all the qualifications of section 9.4.4.1.2 [(interregional economic transmission project criteria)], 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 ~~Section 9.4.4.1.2.1.a~~each RTO's respective tariff.

With this change, MISO will calculate the dollar value of the benefits for a potential interregional economic transmission project using its MTEP analysis (i.e., 100 percent based on adjusted production costs) and PJM will calculate the dollar value of the benefits using its RTEP analysis (i.e., 50 percent based on adjusted production costs and 50 percent based on net load payments). Each RTO will then determine whether the potential interregional economic transmission project meets its individual 1.25-to-1 benefit-to-cost threshold using the RTO's pro rata share of the total cost based on its share of the total dollar value of the benefits.[241]

[240] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 19.

[241] For example, assume a proposed interregional economic transmission project has an estimated cost of $9 million. Also assume that MISO calculates that it will receive

(continued ...)

134. With respect to the comments of AEP and Exelon suggesting that changes should also be made to the interregional economic transmission project method, we dismiss these suggestions since they were not raised in the Complaint.

135. We commend MISO, PJM and its stakeholders for its continued progress in discussing how best to address the limitations of the interregional economic transmission project criteria and thresholds in order to facilitate the approval of interregional economic transmission projects. The Commission recently accepted the proposal by MISO and PJM to remove the $20 million threshold from the JOA,[242] and we believe this is a step in the right direction. However, we disagree with commenters that we should delay action on the Complaint to allow the stakeholder process to address such reforms, given that we find the record justifies ordering relief; accordingly, we here address the Complaint on the merits and direct certain revisions to the JOA and MISO tariff, as discussed above.

4. Market-to-Market Payments

a. JOA

136. Under the terms of the JOA, an interregional economic transmission project must meet several criteria, including having a cost-to-benefit ratio of at least 1-to-1.25. When calculating the benefits, the RTOs use a weighted combination of the change in Adjusted Production Costs and Net Load Payments. Seventy percent of the metric is based on Adjusted Production Costs, which represent the changes in each RTO's production costs, adjusted for interchange purchases and sales. Thirty percent is based on Net Load Payments, which represents each RTO's gross load payment minus the estimated value of congestion-hedging transmission rights in each RTO.[243]

$20 million in benefits from the proposed interregional economic transmission project using its MTEP analysis, and PJM calculates that it would receive $10 million in benefits using its RTEP analysis. Under this example, MISO would conduct its cost-to-benefit calculation by assuming it would be allocated $6 million for the proposed interregional transmission project (because MISO estimated that it would receive two-thirds ($20 million) of the total $30 million of total estimated benefits) and PJM would assume it would be allocated $3 million (because PJM estimated that it will receive one-third ($10 million) of the total estimated $30 million of benefits).

[242] *See infra* n.156.

[243] JOA, § 9.4.

b. Complaint

137. NIPSCO argues that the criteria for approval of an interregional economic transmission project should be amended to include avoidance of market-to-market payments as a benefit.[244] NIPSCO states that while the current MISO-PJM market-to-market redispatch methodology provides an efficient and effective method of reallocating transmission capacity in the short term to provide interregional congestion relief, market-to-market payments also provide an important and currently unutilized measure of the economic benefits of a longer-term transmission solution. NIPSCO states that the RTOs should compile the market-to-market settlement payments data per flowgate, add it to their benefits calculation, and compare this to the cost of a potential interregional economic transmission project that would address the same congested flowgate(s) issue on a permanent basis. NIPSCO submits that in some cases, mitigating the market-to-market payments for one RTO alone may be sufficient to justify the building of an interregional economic transmission project. NIPSCO states that the mitigation of market-to-market payments would be compared to the revenue requirement for the interregional economic transmission project.[245]

138. NIPSCO argues that the currently approved interregional transmission planning process and cost allocation methods in the JOA must be updated to recognize the profound benefits of a facility located in one RTO that presents significant congestion relief for the other RTO. NIPSCO recognizes that such market-to-market payments should be considered for chronic, consistent congestion issues and not be due to temporary issues such as transmission line outages or network reconfiguration due to maintenance, or unexpected equipment failures. NIPSCO states that currently, however, the JOA does not consider avoided market-to-market payments as a benefit justifying

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[244] Market-to-market payments are used to economically account for a congested flowgate. A flowgate is one or more transmission lines, transformers or other transmission facilities monitored for overload during normal operations or contingencies. Instead of relying on the Transmission Loading Relief procedure to alleviate congestion by curtailing transactions between the RTOs, the RTOs redispatch generation in the RTO with the lower cost for redispatch, while the other RTO that has exceeded its Firm Flow Entitlements pays for the redispatch. Firm Flow Entitlements are the amount of firm flow on a flowgate that PJM or MISO is entitled to use based on historical usage.

[245] Complaint at 46.

cross border allocation of transmission costs which may produce uneconomic results to the detriment of customers.[246]

c. Comments Supporting Complaint

139. NIPSCO reiterates its argument that the amount of market-to-market payments far exceeds the cost of new transmission solutions.[247] NIPSCO proposes using both the value of Firm Flow Entitlements and market-to-market payments in the transmission planning process.[248] NIPSCO contends that persistent market-to-market payments and the value of the corresponding Firm Flow Entitlements are good indicators of the need for new transmission and gives examples of several constrained transmission lines where the value of market-to-market payments exceed the cost of new transmission.[249]

140. ATC, ITC, AWEA, Indiana Commission, and Generator Group agree with NIPSCO that interregional economic transmission facilities should be evaluated based upon how they address all known benefits, specifically including, but not limited to, avoidance of future market-to-market payments made to compensate for the reallocation of short-term transmission capacity in the real-time operation of the system.[250] Generator Group asserts that market-to-market payments are a clear indicator of constrained facilities. Generator Group submits that if market-to-market payments are not included in the benefit calculus, then the Commission should direct MISO and PJM to address what cumulative dollar level and over what period should constitute the trigger to assess whether a transmission solution should be explored.[251] AWEA and Indiana Commission propose not only the use of market-to-market payments in assessing interregional economic transmission project benefits, but also the underlying value of the allocated

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[246] *Id.* at 46-47.

[247] NIPSCO March 31, 2015 Pre-Technical Conference Comments at 21-22.

[248] *Id.* at 23-24.

[249] *Id.* at 31, 35-37.

[250] ATC March 30, 2015 Pre-Technical Conference Comments at 4; ITC March 31, 2015 Pre-Technical Conference Comments at 7-8; AWEA March 31, 2015 Pre-Technical Conference Comments at 5.

[251] Generator Group March 31, 2015 Pre-Technical Conference Comments at 17-18, 25.

Firm Flow Entitlement as part of the benefit metrics to justify transmission upgrades.[252] ITC and Generator Group assert that market-to-market payments are a clear indicator of the need for transmission and support requiring all known and potential benefits to be assessed.[253] ITC contends that market-to-market payments are a measure based on actual market data, and should be viewed as an opportunity to address congestion.[254] Generator Group provides suggested revisions to the JOA to address this need.[255]

d. Comments Opposing Complaint

141. MISO and PJM state that the potential avoidance of market-to-market settlement payments is not an independent, incremental benefit metric to the metrics used for current interregional economic transmission projects. MISO and PJM explain that market-to-market payments are a settlement mechanism that shifts congestion dollars between MISO and PJM based on over or under use of each RTO's Firm Flow Entitlements, but does not change the total congestion experienced on a given flowgate. MISO and PJM state that the total congestion for a market-to-market flowgate is the sum of the MISO and PJM congestion and this congestion, applicable to each RTO, is adjusted based on a comparison of Firm Flow Entitlements and Market Flow[256] *via* the market-to-market settlement process to determine the market-to-market payment; however, the total congestion does not change. MISO and PJM explain that the market-to-market payment from one RTO to the other is a mechanism used to adjust the congestion charges for an RTO's over or under usage of their Firm Flow Entitlements. MISO and PJM state that, if there is congestion on a market-to-market constraint, then the total congestion on the constraint will equal the sum of the RTOs' congestion. According to MISO and PJM, the market-to-market payments will not impact this total congestion but result in an

[252] AWEA March 31, 2015 Pre-Technical Conference Comments at 5; Indiana Commission March 31, 2015 Amended Pre-Technical Conference Comments at 4.

[253] ITC August 14, 2015 Comments at 9-10; Generator Group August 14, 2015 Comments at 15.

[254] ITC August 14, 2015 Comments at 9-10.

[255] Generator Group August 14, 2015 Comments at 17.

[256] Market Flows are flows resulting from the dispatch of generation serving load within a market footprint.

adjustment to each individual RTO's congestion costs *via* a market-to-market settlement.[257]

142. MISO and PJM explain that if PJM is the non-monitoring RTO[258] for a MISO flowgate, and if, during an hour when that flowgate is constrained and binding in MISO, the PJM Market Flow on the flowgate is greater than PJM's Firm Flow Entitlements on that flowgate, PJM will make a market-to-market payment to MISO. MISO and PJM state that the result is that PJM's congestion cost on this flowgate is increased while MISO's congestion cost is decreased by the same value; however, the total of the MISO and PJM congestion will remain unchanged. MISO and PJM explain that the market simulation software used by MISO and PJM measures the total congestion for both RTOs, which includes the portion attributable to the market-to-market payments. Thus, MISO and PJM conclude that market-to-market payments should not be added to any simulated congestion, as adding market-to-market payments on top of the total simulated congestion would double count a portion of the congestion.[259]

143. AEP and Exelon, PSEG Companies, and Wisconsin Electric agree with the RTOs.[260] AEP and Exelon claim that including past market-to-market payments as avoided costs double-counts benefits, discounts any upgrades to the system, and ignores market-to-market payments on the next constraint.[261] AEP and Exelon note that historic market-to-market payments are backward looking costs that cannot be extrapolated onto a future system with changed topology with any degree of accuracy.[262] Although AEP and Exelon oppose adding market-to-market payments to the benefit calculation, they

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[257] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 10.

[258] If a flowgate is within an RTO's territory, that RTO is the monitoring RTO. The other RTO is the non-monitoring RTO.

[259] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 10-11.

[260] AEP/Exelon March 31, 2015 Comments at 13-14; PSEG Companies July 15, 2015 Comments at 4; Wisconsin Electric March 31, 2015 Pre-Technical Conference Comments at 7-10.

[261] AEP/Exelon March 31, 2015 Pre-Technical Conference Comments at 12.

[262] AEP/Exelon August 14, 2015 Comments at 11.

believe that using PROMOD analysis to account for generation and transmission outages would improve the accuracy of studies.[263]

144. Exelon states that congestion on the MISO-PJM seam is already considered when evaluating benefits for interregional economic transmission projects in the existing benefit calculation under the JOA. Exelon claims that rewarding market-to-market payments with new transmission will eliminate incentives to properly dispatch the system. [264] PSEG Companies contend that the existence of market-to-market payments is not an indicator that there is anything wrong with either the transmission planning process or the PJM energy and/or capacity markets. PSEG Companies state that market-to-market payments reflect a market-based monetization of the value derived by the RTOs from use of each other's systems. PSEG Companies state that eliminating the payments through the transmission upgrade would only likely result in a misallocation of costs versus benefits.[265]

145. Xcel states that it believes the decision to include the avoidance of market-to-market payments as a benefit for seams projects should be addressed at the RTO level. Xcel states that market-to-market payments are real-time payments that are highly correlated with the Firm Flow Entitlements and the day-ahead commitment process, and therefore, may not be reflective of true congestion.[266] Similarly, Wisconsin Electric asserts that market-to-market payments are not a direct result of the congestion but rather a result of a mismatch between Firm Flow Entitlements and actual flows.[267]

e. <u>Reply Comments</u>

146. In response to AEP and Exelon's proposal to use PROMOD analysis to account for generation and transmission outages, NIPSCO states that although PROMOD is capable of calculating congestion, the RTOs remove this congestion from their benefits calculation.[268] NIPSCO reiterates the total size of market-to-market payments and the

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[263] AEP/Exelon March 31, 2015 Pre-Technical Conference Comments at 13-14.

[264] Exelon October 31, 2013 Corrected Answer at 10-12.

[265] PSEG Companies July 15, 2015 Comments at 4.

[266] Xcel March 31, 2015 Pre-Technical Conference Comments at 11-12.

[267] Wisconsin Electric March 31, 2015 Pre-Technical Conference Comments at 7-10.

[268] NIPSCO April 15, 2015 Reply Comments at 18.

lack of progress in the interregional transmission planning process outside of "one off" transmission projects.[269] NIPSCO reiterates that RTOs adjust the flows in their analysis to account for financial transmission rights and seams, and exclude congestion at the seams.[270]

147. PJM continues to object to adding market-to-market payments on top of calculated project benefits because that would double count project benefits.[271] In response to NIPSCO's criticism of the MISO-PJM Joint Common Market initiative regarding Firm Flow Entitlements, PJM states that this issue is being addressed in Docket No. AD14-3 and NIPSCO should therefore not be allowed to use this proceeding to preempt other stakeholder interests and issues outside of Docket No. AD14-3.[272] NIPSCO argues that the Commission should reject PJM's late-filed September 3 Comments. Nonetheless, NIPSCO asserts that it disagrees with PJM's statements regarding Firm Flow because, among other things, Firm Flow Entitlement values are an integral part of the entire market-to-market system and evaluating the overall value of interregional transmission paths.[273]

148. AEP and Exelon agree with the RTOs that the potential avoidance of market-to-market payments is not an independent benefit metric that should be used to justify transmission investment.[274] AEP and Exelon provide an example of flows changing due to changes in system topology that render the use of past market-to-market payments problematic for estimating the future benefits of transmission projects.[275]

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[269] *Id.* at 28.

[270] NIPSCO August 31, 2015 Reply Comments at 18.

[271] PJM September 3, 2015 Reply Comments at 9-10.

[272] *Id.* at 3.

[273] NIPSCO September 28 Limited Answer at 2-4.

[274] AEP/Exelon April 15, 2015 Reply Comments at 5.

[275] AEP/Exelon August 31, 2015 Reply Comments at 4.

149. Generator Group disagrees with AEP and Exelon's suggestion to use PROMOD analysis and their statement that market-to-market payments are backward looking and thus cannot be used as a basis upon which to approve new transmission.[276]

150. Generator Group contends that numerous transmission projects in MISO and PJM's Quick Hit Analysis were identified *because of* chronic, historical market-to-market payments. Generator Group contends that historic market-to-market payments were the sole criteria that led the transmission owners within MISO and PJM to decide to upgrade the grid. Generator Group contests MISO and PJM's suggestion that market-to-market payments are a settlement mechanism that shifts congestion dollars between MISO and PJM and that total congestion for MISO and PJM on a market-to-market flowgate is not affected by market-to-market payments. Generator Group argues that there *is* chronic "total congestion" on numerous flowgates, yet this congestion is not being used as a data point in MTEP, RTEP and Interregional Planning Stakeholder Advisory Committee processes to call for new transmission. Generator Group argues that this is a deficiency that needs to be corrected and that MISO and PJM should be required to run "total congestion" reports frequently on all sub-regions of their respective RTO and at the seam, to make public the inputs used to develop those reports and the results of those reports, and to address this congestion at annual MTEP, RTEP and joint processes.[277]

f. Commission Determination

151. We deny NIPSCO's request to require MISO and PJM to include avoidance of market-to-market payments as a separate, discrete category of benefits for approval of an interregional economic transmission project. We agree with the commenters that argue that adding market-to-market payments on top of the total simulated congestion would double count a portion of the congestion. In response to NIPSCO and the commenters supporting NIPSCO, we find that market-to-market payments are already included in the production cost calculation part of the benefit analysis. Market-to-market payments are thus not a separate, discrete cost that should be reflected in the benefit analysis but instead are merely transfer payments that have no net effect when both RTOs' systems are taken into account. Therefore, we deny NIPSCO's Complaint on this issue. However, as the Quick Hit analysis demonstrates, we note that market-to-market payments may be used to identify flowgates or other limiting elements along the seam that require further study.

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[276] Generator Group August 31, 2015 Reply Comments at 4-5.

[277] *Id.* at 5-6.

5. Generator Interconnections and Retirements

a. Complaint

152. NIPSCO argues that the Commission should require MISO and PJM to improve coordination regarding the study of generator interconnections and generator retirements that can have material impact across the seam. NIPSCO states that the JOA has proven ineffective in preventing adverse impacts to NIPSCO's transmission system.[278] As an example, NIPSCO states that the interconnection of the Meadow Lake wind farms in PJM has had adverse impacts associated with overloads of NIPSCO's Monticello to East Winamac 138 kV line in MISO.[279] NIPSCO states that although the 2010 PJM System Impact Study concluded that the Meadow Lake project did not require any upgrades to the MISO system, the study indicated that constraints across three NIPSCO lines needed to be resolved to award capacity interconnection rights to the project. NIPSCO states that the interconnection of the Meadow Lake project in PJM required the development and implementation of an operating guide to mitigate constraints on the NIPSCO system. NIPSCO argues that MISO and PJM should jointly study the period between 2015 and the projected in-service date of 2019 to determine what the total impacts are of adding additional generation from the next phases of the Meadow Lake project. Further, NIPSCO argues that if PJM and Meadow Lake decide to bring the other phases of the project online, the existing operating guide should be re-evaluated.[280]

153. NIPSCO also argues that incorrect generator dispatch assumptions for the PJM system were used when analyzing the retirement of the Crawford and Fisk coal stations located in the ComEd territory of PJM. NIPSCO contends that "more realistic" dispatch levels demonstrated that the retirement of these units could result in reliability issues on NIPSCO's system.[281] NIPSCO states that the JOA is currently silent regarding generator retirements. NIPSCO argues that retirements should be analyzed through the use of a single model developed by MISO and PJM which incorporates agreed-upon assumptions.[282]

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[278] Complaint at 50, 52.

[279] *Id.* at 52-54.

[280] *Id.* at 53-54.

[281] *Id.*, Affidavit of Timothy A. Dehring (Dehring Aff.) ¶¶ 32-34.

[282] NIPSCO April 15, 2015 Reply Comments at 24.

154. NIPSCO states that MISO and PJM have made several improvements in their generator interconnection study process since NIPSCO filed its Complaint. However, NIPSCO maintains that further improvements are needed with respect to the approach MISO and PJM each uses to study generator interconnection projects. According to NIPSCO, although the MISO and PJM models may have similar transmission system topology, the two models use different generation dispatch assumptions. NIPSCO states that this disparity in generation dispatch assumptions leads to potential omissions when identifying issues on the system during the interconnection process, such as misrepresentations of the allocation of integration service by MISO and PJM to their respective interconnecting generators. As a result, NIPSCO states that the reduced dispatch of generators with interconnection service results in a reduction in total net loading on facilities that can misrepresent the available loading a facility has, and that this can cause constraints in real-time operations.[283] NIPSCO states that MISO and PJM should develop a single model with agreed-upon assumptions, including dispatch assumptions, and conduct a joint study to ensure all potential issues are identified and mitigated.[284]

155. NIPSCO also states that the RTOs need to establish a process in the JOA to study generator retirements; that retirements should be analyzed in a similar manner as generator interconnections; and that retirements should be analyzed using a single model which incorporates agreed-upon assumptions.[285]

156. NIPSCO requests that the Commission mandate the RTOs enforce the existing generator interconnection coordination requirements under the JOA, and make necessary changes to the JOA to require the RTOs conduct joint studies for generation interconnections and to coordinate retirements with the other RTO. NIPSCO states that, as related to generator interconnection and retirement planning, it seeks one model benchmarked to reality and divorced of regional differences and a defined process for joint or coordinated analyses. For generator retirements, NIPSCO states that it seeks a defined method for allocating costs for upgrades identified through this yet-to-be-defined generator retirement process.[286]

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[283] NIPSCO March 31, 2015 Pre-Technical Conference Comments at 26-30.

[284] *Id.* at 30; NIPSCO July 15, 2015 Comments at 17-18.

[285] NIPSCO July 15, 2015 Comments at 18.

[286] NIPSCO August 14, 2015 Comments at 17-18.

157. NIPSCO states that the following language should be added to section 9.3.3 of the JOA: "The Parties shall develop a joint model to be used in connection with each Party's interconnection service studies."[287] NIPSCO states that corresponding changes to that section should make clear that the RTOs are to use this joint model in carrying out the requirements of section 9.3.3 and that each party shall be obligated to identify issues to be mitigated and clearly communicate those issues to the other party. NIPSCO states that the JOA is silent on the treatment of generation retirements, and that the Commission should direct that the JOA be amended by adding a new section addressing coordination of generator retirements and the allocation of associated costs in line with the cost allocation principles of Order No. 1000. NIPSCO notes that the Commission could either order the RTOs to submit language in a compliance filing or by ordering a targeted settlement process aimed at arriving at consensus language designed to carry out the Commission's findings in an order on the Complaint.[288]

b. <u>Comments Supporting Complaint</u>

158. Several commenters support NIPSCO's proposal. AWEA argues that the interconnection process should require a joint study using a common model that takes into account generation retirements, transmission service requests, and market participant funded upgrades. AWEA states that the interconnection process should also include a cost allocation methodology aligning costs with beneficiaries.[289]

159. ITC notes that, if a generator interconnects in MISO and subsequently causes a reliability concern in PJM, PJM would not address the concern until PJM conducts the facilities study or the following year's RTEP analysis. ITC states that MISO and PJM should coordinate and share information at the feasibility study phase of the generator interconnection and retirement process in order to efficiently address any issues caused by the interconnection.[290]

160. Southern Indiana contends that the different interconnection processes currently used by MISO and PJM result in incorrect assumptions and uncertainties in the interregional economic transmission project evaluation processes. According to Southern Indiana, this prevents the identification of real-time operation constraints that could have

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[287] *Id.* at 17.

[288] *Id.* at 17-18.

[289] AWEA March 31, 2015 Pre-Technical Conference Comments at 6.

[290] ITC March 31, 2015 Pre-Technical Conference Comments at 9.

been identified and corrected in advance during planning studies. Southern Indiana argues that MISO and PJM should conduct joint studies to improve identification and mitigation of potential issues during planning in order to reduce the issues that occur in real-time operations.[291]

161. Xcel states that the Commission should evaluate MISO's process for accrediting external generators in its resource adequacy construct.[292] As new generators are interconnected and studied for deliverability to a neighboring utility's system, Xcel argues that the study should account for and appropriately cost allocate local reliability impacts for power delivered across the seam. Xcel states, however, that already-established firm external resource capacity accreditation should not be jeopardized by modification to the planning process.[293]

162. E.ON states that section 9.3.3 of the JOA requiring MISO and PJM to coordinate to address the impact of interconnection customers on each other's transmission systems has not been followed. E.ON notes that the problems on NIPSCO's system related to the Meadow Lake wind farm were addressed by operational changes rather than network upgrades, but that the JOA requires the installation of network upgrades. E.ON asserts that if MISO had been apprised of the Meadow Lake interconnection on a timely basis, as the JOA requires, MISO would have performed its study during the time that PJM was performing its study, MISO would have determined that upgrades are required in the Duke and NIPSCO areas, PJM would have included those MISO-determined upgrades in its System Impact Study, and the milestone schedule for the Meadow Lake project would have included the schedule to complete these MISO-needed upgrades as a requirement to obtain interconnection service.[294]

163. E.ON states that, because no upgrades were made, there is significant congestion on the NIPSCO system that could have been mitigated to a degree, and that the resulting congestion is costly to generators like Pioneer Trail and Settlers Trail, two of its subsidiaries, in the form of lost energy sales from curtailment. E.ON states that the

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[291] Southern Indiana March 31, 2015 Pre-Technical Conference Comments at 4-5.

[292] Module E-1 of the tariff sets forth MISO's annual resource adequacy construct and explains, among other things, the process by which external resources may qualify as planning resources which are required to provide capacity as required by MISO. MISO, FERC Electric Tariff, Module E-1, § 69A.3.1.c (35.0.0).

[293] Xcel March 31, 2015 Pre-Technical Conference Comments at 13.

[294] E.ON October 31, 2013 Comments at 12-13.

breakdown in coordination between MISO and PJM demonstrates that revisions to the JOA are needed to guard against these types of market-impacting results.[295]

164. E.ON states that its experience in PJM represents another failure to coordinate as required by the JOA. E.ON notes that it submitted an interconnection request in early 2009 for a 100 MW project near the MISO-PJM border. E.ON states that the System Impact Study that PJM undertook for this project did not include any information about impacts and network upgrades needed on the MISO system as JOA section 9.3.3 requires. E.ON states that PJM later informed E.ON that there may be impacts on the MISO system, and that E.ON could have saved time, expense and effort had it been provided this information on a timely basis as the JOA requires. E.ON states that the information provided by NIPSCO demonstrates a failure to employ comparable and non-discriminatory interconnection service.[296]

165. E.ON states that the Commission should exercise its authority under FPA section 206 and order an investigation into the use of operating guides in MISO and in PJM. E.ON states that operating guides should be transparent to the market both for operational and comparability reasons.[297]

166. Generator Group points to the RTOs' application of different methods for modelling criteria and assumptions for baseline reliability analyses, Network Resource Interconnection Studies, Energy Resource Interconnection Studies, generator interconnection studies, and generator retirement studies. Generator Group notes that each RTO has different thresholds and solutions for performing the above studies.[298] Generator Group argues that MISO and PJM need to apply the same standards so project developers can accurately assess data provided in studies, because when a proposed project impacts the seam, it is very difficult for a generation developer to evaluate data provided in MISO and PJM-provided studies, and even to independently assess the market, when MISO and PJM do not apply the same standards.[299]

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[295] *Id.* at 13.

[296] *Id.* at 13-14.

[297] *Id.* at 15-16.

[298] Generator Group March 31, 2015 Pre-Technical Conference Comments at 6-12.

[299] *Id.* at 7-9.

167. Generator Group states that the Commission should require MISO and PJM to submit informational reports twice a year identifying generation projects in the queue that implicated the other RTO, the date the system impact study agreement was signed, the date the other RTO was notified, what was requested of the other RTO and the date when the other RTO provided study results to the siting RTO.[300]

168. Generator Group also notes that there are discrepancies regarding how generation projects in the interconnection queue for each RTO are modeled. Generator Group argues that there should be a guide that describes in detail how to model new generation.[301] Further, Generator Group states that MISO and PJM should employ synonymous terminology, definitions and nomenclature in order for generation developers to review system impact study results at the seam. Generator Group states that synonymous criteria will make it easier for a generation developer to review system impact study results, help to ensure that accurate study results are being prepared, make the process more transparent and facilitate confidence to develop new generation.[302]

169. AEP and Exelon suggest that the status of interconnection studies performed by MISO and PJM, results of those studies, and any operating guides associated with new interconnection requests be posted on the already active Joint and Common Market webpage.[303] According to AEP and Exelon, this would allow affected interconnection customers and transmission owners to track the status of the coordinated study schedule and to identify any errors in the coordinated study and individual models.[304] Similarly, Generator Group states that the status, results, and any operating guides associated with new interconnection requests for all generation within the two RTOs be posted on the MISO and PJM Joint and Common Market webpage since it is difficult to know what projects do and do not impact the seam.[305]

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[300] *Id.* at 23.

[301] *Id.* at 24.

[302] Generator Group August 14, 2015 Comments at 19-20.

[303] The Joint and Common Market webpage describes PJM's and MISO's efforts toward implementation of a joint and common wholesale energy market covering their regions. Joint and Common Market, About, http://www.miso-pjm.com/joint-and-common-market.aspx.

[304] AEP/Exelon March 31, 2015 Pre-Technical Conference Comments at 17.

[305] Generator Group April 15, 2015 Reply Comments at 17.

170. In addition, AEP and Exelon suggest that MISO and PJM consider the feasibility of establishing a common queue for certain areas of MISO and PJM that are very tightly integrated and perform an integrated study process for that queue. AEP and Exelon also suggest eliminating provisional and conditional interconnections. AEP and Exelon state that these interconnections contribute to system congestion and market-to-market payments.[306]

171. Generator Group states that MISO and PJM should sync-up their study timelines for generators. Generator Group states that MISO's timeline is three and 10 years out, and PJM's timeline is five years out, and that both should be on a five-year schedule and proposes specific revisions to the JOA.[307]

172. AWEA argues that the JOA is generally silent regarding retirements. AWEA states that retirements should be analyzed in a similar manner as generator interconnections, including the use of a single model that incorporates assumptions agreed upon by MISO and PJM.[308]

173. AEP and Exelon state that both RTOs can start their analyses on generator deactivations as soon as formal notification to the RTO in which the generator is located is made to the neighboring RTO. In addition, AEP and Exelon state that each RTO must be cognizant of the tariff deadlines for the neighboring RTO. For example, AEP and Exelon note that the rules for generation deactivation in MISO and PJM are different. AEP and Exelon states that PJM allows a generator to retire upon 90-days' notice while MISO requires a 26-week notice for generators that have decided to suspend operations or retire.[309]

c. Comments Opposing Complaint

174. MISO and PJM state that the RTOs are required to conduct coordinated studies associated with interconnection requests, and must include common provisions in their business practice manuals regarding coordination of interconnection studies and network

[306] AEP/Exelon March 31, 2015 Pre-Technical Conference Comments at 17.

[307] Generator Group August 14, 2015 Comments at 18-19.

[308] AWEA March 31, 2015 Pre-Technical Conference Comments at 6.

[309] AEP/Exelon March 31, 2015 Pre-Technical Conference Comments at 19.

upgrades.[310] MISO and PJM also state that they have made improvements, since the filing of the Complaint, in the coordination of their respective generator interconnection queues in both the JOA and their respective business practice manuals. MISO and PJM state that MISO is embarking on a process to reform its Generator Interconnection Queue, and notes that revisions to the JOA would depend on the final outcome of MISO's Queue Reform process.[311]

175. MISO and PJM do not believe revisions to the JOA are required at this time to coordinate planning of generation retirements. MISO and PJM state that the RTOs currently exchange information about new retirement requests, and that new retirements are then incorporated into each region's planning models and shared in the model development processes. MISO and PJM state that each RTO's deactivation process for generator retirements is defined in their respective regional tariffs, and that, reliability issues caused by the retirement of an external generation unit in a neighboring system is evaluated by the RTOs together with their stakeholders, at which time the RTOs coordinate with the impacted transmission owners to identify and plan for construction of necessary transmission upgrades. MISO and PJM note that the "Annual Data and Information Exchange Requirement" in the JOA already includes provisions for the exchange of power flow models for the planning horizon, which include generation development and retirements.[312] MISO and PJM state that the RTOs are open to considering improved coordination between the MISO and PJM planning for generator retirements but note that the different market constructs and the enhanced Order No. 1000 coordination make this goal difficult to achieve. MISO and PJM note that potential enhancements with respect to interregional coordination of generator retirements are more appropriate for consideration in the stakeholder process.[313]

176. AEP and Exelon state that reliability needs due to retirements should be dealt with in each RTO's reliability planning process and that it would not be appropriate within the JOA to attempt to change the criteria of each RTO for evaluating retirements. AEP and Exelon state, moreover, that there is no reason to look at cost allocation for retirements

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[310] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 13 (citing JOA, § 9.3.3).

[311] MISO/PJM August 14, 2015 Comments at 7. *See Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,247 (2016).

[312] MISO/PJM August 14, 2015 Comments at 8.

[313] MISO/PJM March 31, 2015 Pre-Technical Conference Comments at 14.

since they are just one of many changes to the system, and interconnected companies need to plan for these changes just as they plan for other changes to the system.[314]

177. MISO Transmission Owners state that new generator interconnections and unit retirements should already be taken into account under the existing terms of the JOA, and that no change to the language of the JOA should be needed. MISO Transmission Owners state that, to the extent the terms of the JOA are not being enforced, this should be addressed within the Interregional Planning Stakeholder Advisory Committee.[315]

d. Reply Comments/Answers

178. Generator Group states that it is imperative that the Commission require proper modeling by MISO and PJM of external generation. Generator Group states that external generation can have a substantial impact on deliverability within the neighboring RTO. Generator Group notes that approximately 3,300 MW of generation external to MISO entered MISO's August 2014 Definitive Planning Phase, the vast majority of which are located within PJM. Generator Group agrees with Xcel that the Commission should address this issue in this docket, and states that the outcome has a direct bearing on establishing a just and reasonable joint and common market at the MISO-PJM seam.[316]

179. Generator Group supports AEP and Exelon's suggestion that MISO and PJM maintain a common queue for certain areas of MISO and PJM that are very tightly integrated and perform an integrated study process for that queue. Generator Group states that such may provide a means to reconcile the different dispatch and modeling assumptions that each RTO applies, and that this approach should be explored in this docket rather than in the stakeholder process. Generator Group states that, until a new common queue is established, the Commission should require that current modeling assumptions for generation interconnection be assessed, substantiated and reconciled for common use.[317]

180. Generator Group disagrees with AEP and Exelon's suggestion that provisional and conditional interconnection service be eliminated. Generator Group states that provisional and conditional interconnection service is allowed only up to levels that can

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[314] AEP/Exelon August 14, 2015 Comments at 12-13.

[315] MISO Transmission Owners October 31, 2013 Comments at 13-14.

[316] Generator Group April 15, 2015 Reply Comments at 14-16.

[317] *Id.* at 17.

be handled by existing capacity, and that, if there is congestion, the service is curtailed because it is only an as-available, conditional service. Generator Group states, therefore, that AEP and Exelon have not shown that provisional and conditional service is a cause of congestion and market-to-market payments.[318]

181. Generator Group argues that, in order to properly assess flows on the RTOs' systems and at the seam, as well as assess the need for transmission, the RTOs must use a joint model that incorporates justified dispatch assumptions.[319] Generator Group expresses support for NIPSCO's recommendation to amend section 9.3.3 of the JOA to require that: "The Parties shall develop a joint model to be used in connection with each Party's interconnection service studies."[320]

182. PJM states that NIPSCO fails to acknowledge the improved coordination between the RTOs with regard to their respective generator interconnection queues and that it fails to demonstrate any need to make further revisions to the generator interconnection process outside of the stakeholder processes. PJM states that revisions to the JOA provide for the exchange of power flow models on an annual basis for projected system conditions including planned generation development and retirements. PJM states that NIPSCO's suggestion concerning the allocation of costs for upgrades needed due to a generator's retirement is "far wide of what is currently required of a generator choosing to deactivate its unit," and that load should not be required to pay for upgrades needed to address reliability problems in another region just because a generator retired. PJM states that this issue is one which would require a national policy change and, thus, should have been raised in the context of the Commission's deliberations leading up to Order No. 1000 rather than in this proceeding.[321]

183. MISO states that the common provisions used in each RTO's manuals include those related to the exchange of power flow modeling data; the coordination of study results; provisions allowing participation in studies by the impacted party under certain circumstances; the coordination of Facilities Study agreements; and submission to the Interregional Planning Stakeholder Advisory Committee of the RTOs' list of

[318] *Id.* at 18.

[319] *Id.* at 9-10.

[320] Generator Group August 31, 2015 Reply Comments at 10 (citing NIPSCO August 14, 2015 Comments at 17).

[321] PJM September 3, 2015 Reply Comments at 12-13.

interconnection requests that could potentially impact the systems of both parties.[322] MISO notes that NIPSCO has had, and will continue to have, an opportunity to present such proposals to stakeholders.[323]

e. <u>Commission Determination</u>

184. We deny NIPSCO's request to require MISO and PJM to use a joint model to study generator interconnection requests. As discussed above, the JOA currently requires MISO and PJM to use a joint interregional study model with a single set of agreed-upon assumptions and provides stakeholders with an opportunity to provide comments on the joint model and assumptions used.[324] In addition, the MISO and PJM business practice manuals require that each RTO coordinate potential impacts to the other RTO's transmission system due to interconnection requests.[325] We will also not require, as Generator Group suggests, MISO and PJM to apply the same standards in their respective interconnection studies, the establishment of a common queue between MISO and PJM, or that MISO and PJM sync up their study timelines. In addition, we deny ITC's request to require MISO and PJM to coordinate and share information at the feasibility study phase of the generator interconnection and retirement process. As explained above, we find that the currently existing provisions of the JOA related to modeling and interconnection studies, when appropriately adhered to, are just and reasonable.

185. Nevertheless, we find that including in the JOA details about the coordination of interconnection studies currently found only in the MISO and PJM business practice manuals will provide additional transparency that will help ensure MISO and PJM are

[322] MISO October 31, 2013 Answer at 41.

[323] *Id.* at 42-43.

[324] JOA, § 9.3.6.2(b)(vi).

[325] PJM Business Practice Manual 14A (Generation and Transmission Interconnection Process), § 1.12.1 (Study of PJM Interconnection Request impacts on MISO transmission) and 1.12.2 (Study of MISO Interconnection Request impact on PJM Transmission); MISO Business Practice Manual 15 (Generator Interconnection Business Practice Manual), § 6.3.1 (Study of PJM Interconnection Request impacts on MISO Transmission) and § 6.3.2 (Study of MISO Interconnection Request impact on PJM Transmission).

following the JOA coordination procedures.[326] For example, there is a disagreement about whether MISO and PJM sufficiently coordinated the generator interconnection study for NIPSCO's Meadow Lake wind farm, which may be due in part to the lack of details in the JOA about the what level of coordination is required. Including a single description of the interconnection coordination requirements in the JOA rather than in separate business practice manuals will provide more clarity regarding the coordination requirements in the JOA. While the language in the MISO and PJM business practice manuals appears to be generally consistent,[327] there is language in MISO's business practice manual that does not appear to have corresponding language in PJM's business practice manual, and vice versa.[328] In addition, the business practice manuals have deadlines for when MISO and PJM must share information regarding interconnections studies,[329] and including those deadlines in the JOA is consistent with our earlier requirement to include in the JOA specific deadlines for each step in the Coordinated System Plan Study process.[330] Therefore, to provide transparency and more clarity regarding the interconnection coordination requirements in the JOA, we direct MISO and PJM to submit, within 60 days of the date of issuance of the order, revisions to the JOA to include the description of the interconnection coordination procedures that are currently in the MISO and PJM business practice manuals. Because MISO and PJM will have to integrate the language currently in their separate business practice manuals to create a new single set of revisions to the JOA, we will review the language they propose on compliance to ensure it is consistent with the coordination requirements in the JOA that the Commission previously accepted.

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[326] The JOA states, "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." *Id.*

[327] The JOA states, "Both Parties' manual language shall be coordinated so as to ensure the communication of requirements is consistent…." *Id.*

[328] Compare PJM Business Practice Manual 14A (Generation and Transmission Interconnection Process), § 1.12 (Coordination of studies between PJM and MISO) and its sub-sections to MISO Business Practice Manual 15 (Generator Interconnection Business Practice Manual), § 6.3 (Coordination of studies between PJM and MISO) and its sub-sections. *See also*, PJM BPM at section 1.14 (Interim Deliverability Studies).

[329] *See supra* n. 325.

[330] *See* the Transmission Planning Cycles section of this order, above.

186. We also grant NIPSCO's request to require MISO and PJM to revise the JOA so that they coordinate generator retirement studies. NIPSCO has demonstrated that the lack of coordination for generator retirements has caused harm to parties located near the MISO-PJM seam. In particular, NIPSCO provided testimony indicating that PJM utilized unrealistic dispatch assumptions when it studied the retirement of the Crawford and Fisk generating plants in the ComEd territory of PJM, which caused PJM to fail to identify required upgrades and masked potential problems within MISO, including overloads on NIPSCO's system.[331] NIPSCO also provided testimony indicating that separate analyses conducted by NIPSCO and MISO identified reliability issues on NIPSCO's system caused by the retirement of these two generators within PJM. Given the apparent incongruence between the assumptions and results of the MISO and PJM studies and the resulting harm, we find that greater coordination on this issue is necessary, and that the current lack of generator retirement coordination requirements in the JOA is unjust and unreasonable. Requiring that MISO and PJM coordinate their generator retirement processes, to include, among other things, coordinating their dispatch assumptions, will bring those processes in line with existing requirements for coordinating generator and transmission interconnection requests[332] and long-term firm transmission service requests.[333] Recognizing the effort required to establish generator retirement study coordination processes, we direct MISO and PJM to work with stakeholders to propose revisions to the JOA that require the RTOs to coordinate their generator retirement studies. We direct the RTOs to submit informational status reports on their progress every 60 days starting from the date of the issuance of this order and to propose the required changes no later than December 15, 2016.

187. We find AWEA's and Xcel's cost allocation proposals, Xcel's proposal regarding accrediting external generators, and AEP and Exelon's proposal regarding provisional and conditional interconnections to be beyond the scope of the Complaint, which solely addresses MISO-PJM studies and coordination. We also find that E.ON's proposal that the Commission exercise its authority under FPA section 206 to order an investigation into the use of operating guides in MISO and PJM is beyond the scope of this proceeding. Such operating guides are for internal dispatch and congestion management and are not related to the interregional coordination of interconnection studies. Although there may be benefits to requiring synonymous terminology, definitions, and assumptions, as well as a guide for modeling new generation, as Generator Group suggests, we will not impose

[331] Complaint, Dehring Aff. ¶¶ 32-34.

[332] JOA, § 9.3.3.

[333] *Id.* § 9.3.4.

these new requirements at this time. We will also not require revisions to the procedures by which MISO and PJM model external generation as proposed by Generator Group. The JOA, after the revisions required above, should sufficiently address the concerns raised in the Complaint.

188. We deny requests by AEP and Exelon and Generator Group to require that MISO and PJM post the status of interconnection studies on the Joint and Common Market webpage and to require MISO and PJM to submit informational reports twice a year identifying generation projects in the queue as beyond the scope of this proceeding. We note that MISO and PJM continue to monitor the existing generation interconnection queue processes. We encourage interested parties to continue to discuss any needed improvements, including those proposed by AEP and Exelon and Generator Group, in the stakeholder process.

The Commission orders:

(A) NIPSCO's Complaint is hereby granted in part and denied in part, as discussed in the body of this order.

(B) MISO and PJM are hereby directed to submit a compliance filing, within 60 days of the date of this order, as discussed in the body of this order.

(C) MISO and PJM are hereby directed to submit an informational filing, within 120 days of the date of this order, with respect to how MISO and PJM could potentially conduct the Coordinated System Plan Study on a single, common timeline with the MTEP and the RTEP, as discussed in the body of this order.

(D) MISO and PJM are hereby directed to submit an informational filing, within 180 days of the date of this order, with respect to how MISO and PJM could use a joint model with the same assumptions and criteria for reliability and economic planning related to interregional transmission issues, as discussed in the body of this order.

(E) MISO and PJM are hereby directed to submit informational status reports every 60 days starting from the date of this order with respect to coordination of generator retirement studies, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.