VIA ELECTRONIC DELIVERY

July 10, 2013

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

Re:  Midcontinent Independent System Operator, Inc.’s and
     MISO Transmission Owners’ Compliance Filing for Order No. 1000,
     Regarding Interregional Transmission Project Coordination and Cost
     Allocation with PJM Interconnection, L.L.C.
     Docket No. ER13-___-000

Dear Secretary Bose:

Pursuant to section 206 of the Federal Power Act (“FPA”), 16 U.S.C. § 824e, and
Order Nos. 1000, 1000-A, and 1000-B\(^1\) of the Federal Energy Regulatory Commission
(“FERC” or “Commission”), the Midcontinent Independent System Operator, Inc.
(“MISO”),\(^2\) and the MISO Transmission Owners\(^3\) (collectively, the “Filing Parties”),

\(^1\) *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) (hereinafter also collectively referred to as “Order No. 1000,” unless otherwise indicated by the text or the context).

\(^2\) Formerly the Midwest Independent Transmission System Operator, Inc., until its name changed effective April 26, 2013.

\(^3\) The MISO Transmission Owners join MISO in support of Section III.C of this filing to the extent that the filing proposes revisions to Section 9.4.3.2 of the MISO-PJM JOA. The supporting MISO Transmission Owners for this filing consist of: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Gulf States Louisiana, L.L.C.: Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Great River Energy: MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Otter Tail Power Company; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; and Wabash Valley Power Association, Inc. Each of the MISO Transmission Owners, both individually and as a group, reserve the right to submit separate comments on or protests of this filing.
respectfully submit this compliance filing proposing revisions to the Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. (“MISO-PJM JOA”), to address the interregional coordination and cost allocation requirements of Order No. 1000. Concurrently, MISO is also submitting related amendments to Attachment FF of its Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”) to comply with the requirement of Order No. 1000 that the Tariff identify any agreements that address such interregional coordination and cost allocation requirements; and PJM is separately submitting related revisions to its tariff. MISO and PJM Interconnection, L.L.C. (“PJM”) agree on many aspects of their proposed compliance with Order No. 1000’s interregional requirements, but they disagree on certain matters, as discussed below. Given such disagreement, MISO and PJM are making separate interregional compliance filings, so that the Commission can consider the parties’ respective proposals on the areas of disagreement.

MISO and PJM agree on the JOA revisions related to interregional coordination, although they disagree on some proposed revisions regarding interregional cost allocation. To facilitate the Commission’s consideration, MISO and PJM have developed an essentially common description of the JOA revisions on which they agree, with minor adjustments in their respective filings (herein, section III.A) to reflect that the discussion is being provided from the perspective of either MISO or PJM. MISO and PJM have also agreed to use substantially the same language in describing the stakeholder process that led to the development of the proposals discussed herein, which MISO discusses in Part II of this letter.

Despite engaging each other and each other’s stakeholders on numerous occasions, as evidenced in Part II.A below, MISO and PJM both use a partly different basis for cost allocation, and, given the difficulties inherent in bridging the differences between the two approaches, were unable to reach complete agreement regarding the cost allocation of interregional transmission projects. Notwithstanding, given that in MISO’s experience cost allocation has historically been an iterative and evolutionary process, MISO anticipates working in coordination with PJM and its other regional neighbors as the interregional planning process continues to develop.

In light of the linkages between MISO’s and PJM’s regional processes, on the one hand, and the proposed interregional process, on the other hand, the Filing Parties request that the revisions proposed in this filing become effective on January 1, 2014 or, alternatively, June 1, 2014, as further described in section V.A of this letter.

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4 Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., designated as MISO’s Second Revised Rate Schedule FERC No. 5; and as PJM’s Second Revised Rate Schedule FERC No. 38.

5 MISO and PJM agree to all proposed revisions to the JOA included in Tab A to this letter, with the exception of the changes MISO proposes to Section 9.4.3.2.1 (“Cost Allocation for Cross-Border Baseline Reliability Projects”), with which PJM and the PJM Transmission Owners disagree.
I. BACKGROUND

A. Interregional Coordination and Cost Allocation Requirements of Order No. 1000

Order No. 1000 amended the regional transmission planning and cost allocation requirements of Order No. 890 by imposing a number of requirements regarding new transmission facilities selected in a regional transmission plan for purposes of cost allocation, and the interregional coordination, and cost allocation, of transmission facilities that involve interregional benefits. The Commission required jurisdictional transmission providers to make compliance filings concerning Order No. 1000’s regional planning and cost allocation requirements, and its interregional coordination and cost allocation requirements, respectively.

The original due date for compliance filings for regional requirements was extended to October 25, 2012, and the due date for compliance filings for interregional requirements was extended to July 10, 2013. As a Regional Transmission Organization (“RTO”), MISO submitted on October 25, 2012, its Order No. 1000 regional compliance filing, which in large part was conditionally accepted by the Commission on March 22, 2013. The March 22 Order also accepted the Filing Parties’ proposal in Docket No. ER13-186-000 to remove, effective June 1, 2013, the regional cost allocation for MISO’s Baseline Reliability Projects (“BRPs”). On October 25, 2012, PJM, which is also an RTO, submitted its Order No. 1000 regional compliance filing in Docket No. ER13-198-000, which was also accepted on March 22, 2013.

The present filing addresses Order No. 1000’s interregional coordination and cost allocation requirements, as between MISO, PJM, and the PJM Transmission Owners.

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7 Order No. 1000 at P 393-404, 415-21, 435-50, 454-55, 458, 465-67, 475-81; Order No. 1000-A at P 500-05, 509-12, 518-22; Order No. 1000-B at P 64.

8 Order No. 1000 at P 578-84, et seq.; Order No. 1000-A at P 634, et seq.; Order No. 1000-B at P 72.


12 Id. at P 518-29.

13 With regard to PJM’s Order No. 1000 interregional compliance filing, MISO’s understanding is that the PJM Transmission Owners have filing rights for cost allocation while PJM’s filing will primarily
Unless otherwise indicated, MISO, PJM, and the PJM Transmission Owners agree on the aspects of the interregional compliance proposal described herein. Such agreed aspects will be reflected both in MISO’s current filing and in PJM’s and the PJM Transmission Owners’ concurrent interregional compliance filing. Accordingly, to facilitate discussion, this filing will often describe such agreed matters as having been proposed or otherwise addressed by both MISO, PJM, and the PJM Transmission Owners, albeit separately, meaning that their concurrent filings have proposed common MISO-PJM JOA and tariff revisions that they agree on.

B. Existing MISO-PJM Joint Operating Agreement

On December 31, 2003, pursuant to earlier Commission directives,14 MISO and PJM filed the MISO-PJM JOA, which the Commission conditionally accepted on March 18, 2004.15 The JOA Order directed MISO and PJM to “amend the JOA to provide for sharing of the relevant transmission owner plans and for coordination between the RTOs as each develops its regional plan.”16 MISO and PJM submitted a compliance filing on April 2, 2004 pursuant to the Commission’s directives in the JOA Order, revising the JOA to require the RTOs to share, on an ongoing basis, information that arises in the performance of single party planning activities as is necessary or appropriate for effective coordination, including the identification of proposed transmission system enhancements that may affect each party’s respective system. The Commission accepted these changes on August 5, 2004.17

On November 18, 2004, in the course of ruling on transmission rate proposals intended to eliminate rate pancaking between MISO and PJM, the Commission directed MISO and PJM to “develop a proposal for allocating to the customers in each RTO the cost of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO.”18

On May 17, 2005, MISO and PJM submitted a cross-border cost allocation proposal for reliability projects, which the Commission conditionally accepted on address interregional coordination. MISO further understands that the PJM Transmission Owners plan to file a separate compliance filing on interregional cost allocation.

16 Id. at P 55.
The approved method would allocate the costs of cross-border projects using a “load flow model that identifies project beneficiaries following cost causation principles.” The Commission determined that this proposal provided “a regional approach to transmission planning that more accurately identifies the beneficiaries and allocates the associated costs of cross-border projects than the existing license plate rate structure” and would “ease the burden on local loads, that were traditionally responsible for network upgrades, by identifying regional beneficiaries of such upgrades.” However, the Commission required MISO and PJM to provide a more detailed description of the joint RTO planning model to be used for cross-border cost allocation.

On March 21, 2006, the RTOs submitted a compliance filing explaining that the cross-border cost allocation process would employ a transfer distribution factor (“DFAX”) analysis to calculate the size of each RTO’s flows affecting the constraint requiring relief from a cross-border reliability project. Since the RTOs could not agree on how counterflow should be netted against positive flow in the allocation formula, each RTO submitted its own netting proposal. The Commission ultimately accepted MISO’s proposal on January 31, 2008. The MISO-PJM JOA refers to the cross-border reliability projects as Cross-Border Baseline Reliability Projects (“CBBRPs”).

MISO and PJM next filed on January 28, 2009, a proposal for cost allocation of economic cross-border projects, which the Commission accepted as just and reasonable on November 3, 2009. The MISO-PJM JOA currently refers to cross-border projects pertaining to economic benefits as Cross-Border Market Efficiency Projects (“CBMEPs”). The cost allocation method for CBMEPs combines aspects of the benefit formulas already used by MISO and PJM for cost allocation of their respective economic projects on a regional basis. CBMEP costs are allocated to each RTO in proportion to the present value of the RTO’s share of the annual benefits that are calculated for the project.

Article IX of the current MISO-PJM JOA addresses coordinated regional transmission planning. Pursuant to section 9.1.1 of the JOA, the Inter-RTO Steering Committee (a committee that is charged with facilitating interregional coordination and

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20 Id. at P 3.
21 Id. at P 10.
22 Id. at P 19.
24 Id. at P 21.
addressing interregional problems, including development of a Joint and Common Market between MISO and PJM)\textsuperscript{26} formed a Joint RTO Planning Committee (“JRPC”) comprised of staff members from each RTO. The JRPC is responsible for coordinating the coordinated system planning implemented by Article IX, including preparing, on a regular basis, an inter-RTO transmission plan, called the Coordinated System Plan. Pursuant to section 9.1.2, MISO and PJM also formed an Inter-regional Planning Stakeholder Advisory Committee (“IPSAC”), which facilitates stakeholder review and input into coordinated system planning with respect to development of the Coordinated System Plan. Further, in support of coordinated system planning, the MISO-PJM JOA requires the exchange of planning data and information, generally as requested.\textsuperscript{27} Section 9.3 requires coordination of regional transmission planning between MISO and PJM as well as development of a Coordinated System Plan “to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the competitiveness of electricity markets.”\textsuperscript{28} The Coordinated System Plan is “an integral part of the expansion plans of each party” and includes the results of Coordinated System Plan studies as well as coordinated, ongoing analyses of requests for interconnection and long-term firm transmission service.\textsuperscript{29} MISO and PJM perform coordination studies used to develop the Coordinated System Plan every three years, with sensitivity analyses being performed, as required, during the off years based on a review by the JRPC and IPSAC of discrete reliability problems or operability issues that arise due to changing system conditions.\textsuperscript{30}

The Coordinated System Plan cannot be finalized until the IPSAC has had an opportunity to review and respond to it.\textsuperscript{31} Similarly, proposed cost allocations of CBBRPs and CBMEPs calculated by the JRPC pursuant to section 9.4.3 of the MISO-PJM JOA must be reviewed by the IPSAC and other appropriate multi-state entities and posted on the websites of both PJM and MISO. The JRPC must solicit such stakeholder input and take into consideration in arriving at a consensus allocation of costs.

II. DEVELOPMENT OF COMPLIANCE FILING THROUGH STAKEHOLDER PROCESSES OF MISO AND PJM

As required by Order No. 1000,\textsuperscript{32} MISO provided its stakeholders with reasonable opportunity to provide input for the development of the interregional compliance proposal

\textsuperscript{26} Preamble of Agreement Concerning Inter-regional Coordination, Including Development of Joint and Common Market.

\textsuperscript{27} MISO-PJM JOA at section 9.2.

\textsuperscript{28} Id. at section 9.3.

\textsuperscript{29} Id. at section 9.3.2.

\textsuperscript{30} See id. at section 9.3.5.2.(a).

\textsuperscript{31} Id. at section 9.3.5.1.

\textsuperscript{32} Order No. 1000 at P 466.
submitted herein. On information and belief, PJM also provided its stakeholders with the opportunity to provide such input.

A. Joint Stakeholder Discussion

MISO and PJM held joint meetings with their respective stakeholders on the following dates:

**Joint Stakeholder Meetings**

<table>
<thead>
<tr>
<th>Date</th>
<th>Primary Discussion Items</th>
<th>Meeting Location</th>
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| October 24, 2012 | • Order 1000 Interregional Requirements Review  
                   • Review of Current MISO-PJM JOA  
                   • Joint Common Market Related Issues  
                   • Potential Opportunities Discussion  
                   • Stakeholder Process and Work Plan | Carmel, IN             |
| December 5, 2012 | • MISO Order 1000 Regional Compliance Filing Overview  
                   • PJM Order 1000 Regional Compliance Filing Overview  
                   • Review of Stakeholder Feedback; responses of MISO and PJM  
                   • Updated Order 1000 Work plan | Conference Call/WebEx   |
| January 16, 2013 | • Review Generator Interconnection Discussions at JCM  
                   • Order 1000 Interregional Planning Compliance Proposals  
                   o Model and Data Exchange  
                   o JRPC and IPSAC Governance and Responsibilities  
                   o Annual Issues | Norristown, PA          |
### Evaluation
- Interregional Study Process
- MISO’s Order 1000 Interregional Cost Allocation Proposal
- PJM Attachment H Transmission Owners – Cost Allocation

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<tr>
<th>Date</th>
<th>Topics</th>
<th>Location</th>
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| February 13, 2013  | • Review Stakeholder Feedback from 1/16 Meeting  
• Order 1000 MISO-PJM JOA Enhancements  
  o JRPC and IPSAC Governance and Responsibilities  
  o Model and Data Exchange  
  o Coordinated System Planning  
• Update on MISO-PJM JOA Cost Allocation Proposals | Carmel, IN      |
| March 13, 2013     | • Review Stakeholder Feedback / Updates to MISO-PJM JOA Language  
• Review of Order 1000 Interregional Compliance Requirements | Conference Call/WebEx |

### B. MISO Regional Stakeholder Discussion

MISO provided updates on the discussions with PJM regarding the Order No. 1000 interregional compliance requirements in numerous meetings with its Planning Advisory Committee (“PAC”), Planning Sub-Committee (“PSC”) and its RECB Task Force (“RECB TF”). A list of these meeting can be found in Tab C to this letter.

### C. PJM Regional Stakeholder Discussion

PJM also engaged its stakeholders in discussions related to compliance with the interregional requirements of Order No. 1000.
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III. DISCUSSION OF TARIFF AND MISO-PJM JOA REVISIONS

A. Interregional Coordination and Planning

Consistent with Order No. 714, PJM has served as the official filing party for the MISO-PJM JOA, with MISO filing a certificate of concurrence with the Commission. Because the RTOs disagree on some of the proposed MISO-PJM JOA revisions pertaining to the interregional requirements of Order No. 1000, MISO is submitting herein the entire MISO-PJM JOA with its proposed revisions and contemporaneously withdrawing its existing certificate of concurrence, and MISO’s understanding is that PJM will also file the entire MISO-PJM JOA with its proposed changes.

1. The MISO-PJM JOA Meets the Requirements of Joint Evaluation, Data Exchange and Transparency Across the Two Regions

Order No. 1000’s interregional transmission coordination requirements obligate transmission providers to commit to coordinate and share the results of each transmission planning region’s regional transmission plans to identify possible transmission facilities that may more efficiently or cost-effectively address the individual needs of each RTO’s local and regional planning processes. To comply with this requirement, the neighboring RTOs are required to improve upon their existing regional transmission planning processes to: (i) identify and jointly evaluate possible interregional transmission facilities that more efficiently or cost-effectively address separate regional transmission facilities; and (ii) jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions. Order No. 1000 requires the public utility transmission providers in neighboring regions to engage in “joint evaluation” of proposed interregional projects, including sharing of information regarding the respective needs of each region and potential solutions to those needs, as well as identification and evaluation of interregional transmission alternatives to regional needs of neighboring planning regions. In addition, Order No. 1000 requires transmission providers to develop procedures that provide for “data exchange” and “transparency.”

From its inception, the MISO-PJM JOA went far beyond mere sharing of information. Rather, inter alia, the MISO-PJM JOA provides a specific vehicle for the analysis and coordination of cross-border projects between the RTOs through the MISO-PJM JOA’s formal committee structure.

34 See Order No. 1000 at P 394.
35 E.g., id. at P 435.
36 See id. at P 398.
37 Id. at P 454.
38 Id. at P 458.
The MISO-PJM JOA currently provides for joint planning between the RTOs through the following two formal committees established under Article IX of the MISO-PJM JOA: (i) the JRPC, which is comprised of staff representatives from both RTOs; and (ii) the IPSAC, which is a committee open to all stakeholders from both regions. The specific roles and responsibilities of each committee are described as follows:

- **JRPC.** The responsibilities and activities of the JRPC are detailed in section 9.1.1 of the MISO-PJM JOA. The JRPC is the decision-making body for coordinated system planning between the MISO and PJM. Additionally, the JRPC is responsible for coordinating all planning activities, including the preparation of a Coordinated System Plan applicable to both systems that integrates the RTO’s respective regional transmission plans, resolves impacts across the seams and addresses results of the underlying analyses.

- **IPSAC.** The role of the IPSAC is detailed in section 9.1.2 of the MISO-PJM JOA. The IPSAC is responsible for reviewing identified transmission issues and providing input into coordinated system planning to the JRPC annually, including whether a Coordinated System Plan study should be performed. The Coordinated System Plan is finalized only after the IPSAC has had an opportunity to review it and respond.

In accepting the MISO-PJM JOA, the Commission found that the planning process, through this committee structure, includes extensive RTO and stakeholder input. In complying with the mandates of Order No. 1000, the RTOs have taken this opportunity to reorganize and, in some instances, enhance the provisions that describe these two committees. Such committees establish the framework under which the RTOs can coordinate and share information, consider potential solutions through the studies performed, and identify and jointly evaluate more efficient or cost-effective solutions to regional needs. Within this framework, the RTOs propose that the JRPC and the IPSAC meet at least annually to review each RTOs regional plan for integration into the Coordinated System Plan, and review and consider whether a Coordinated System Plan study should be performed. In addition, as the decision-making body for coordinated system planning, the JRPC is required to meet at a minimum of twice per year and more

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39 See MISO-PJM JOA at section 9.1.
40 Id. at section 9.1.2.
41 See id. at section 9.3.5.1.
42 See JOA Order at P 49.
43 See Order No. 1000 at P 394.
44 While the MISO-PJM JOA requires that the JRPC and IPSAC meet at least annually, the current practice has been and it is expected to continue going forward, that the RTOs will meet more often than annually.
45 See MISO-PJM JOA at section 9.1.2.
frequently during the development of a Coordinated System Plan.\textsuperscript{46} The RTOs also propose to revise section 9.1.2 to require that the IPSAC meet at least annually (and more frequently during the development of a Coordinated System Plan) to review identified transmission issues for the purpose of coordinated system planning.

2. The JOA Meets the Sharing of Information Requirements of Order No. 1000

Order No. 1000 clarified that transmission providers must do more than simply commit to share their regional transmission plans and other transmission planning information.\textsuperscript{47} In order to comply, each transmission provider must develop and implement additional procedures that provide for sharing of information regarding the respective needs of each neighboring transmission planning region and potential solutions to those needs.\textsuperscript{48} In addition, transmission providers must describe the procedures they will utilize to identify and evaluate whether interregional transmission facilities are more efficient or cost effective than regional transmission facilities, such as a description of the type of transmission studies that will be conducted to evaluate conditions on a neighboring system and determine whether interregional transmission facilities are more efficient or cost effective than regional facilities.\textsuperscript{49}

With regard to the sharing of information, the MISO-PJM JOA currently provides that each RTO will prepare a regional transmission planning report that documents its regional plan.\textsuperscript{50} Section 9.3.1 also provides that each RTO will share, on an ongoing basis, (i) information stemming from its regional planning process that may be necessary or appropriate for effective coordination between the regions, and (ii) identified transmission enhancements that may affect the neighboring RTO’s system.\textsuperscript{51} The RTOs also propose to amend the MISO-PJM JOA to include the sharing of information regarding notices to deactivate or mothball existing generation resources.\textsuperscript{52}

The MISO-PJM JOA also provides for the development of a Coordinated System Plan that is a result of the coordination stemming from the regional planning conducted under the JOA. Specifically, section 9.3.2 of the MISO-PJM JOA provides for the coordination of any studies needed to ensure the reliability or operation of the transmission system, including ongoing analysis of interconnection and long-term firm transmission service requests. Results of such coordinated studies will be included in the Coordinated

\textsuperscript{46} See id. at section 9.1.1.
\textsuperscript{47} See Order No. 1000 at P 398.
\textsuperscript{48} See id. at P 398.
\textsuperscript{49} See id.
\textsuperscript{50} MISO-PJM JOA at section 9.3.1.
\textsuperscript{51} Id.
\textsuperscript{52} See id.
To the extent the JRPC combines with or participates in similarly established joint planning committees among multiple planning entities, the RTOs’ coordinated planning analyses may be integrated into any joint coordinated planning analyses engaged in by those committees.54

Additionally, the RTOs propose revisions to section 9.3.5.2 of the MISO-PJM JOA to clarify that the sharing of information and coordination of studies for the Coordinated System Plan shall include an annual review of transmission issues identified by each RTO, including issues from each respective RTO’s market operations and annual planning processes, as well as issues raised by third parties.55 This annual issues review will be administered by the JRPC.56

3. The JOA Meets the Order No. 1000 Requirements Concerning Identification and Joint Evaluation of Interregional Transmission Facilities

Included in this filing, the RTOs propose to add to their current two-part coordinated system planning process. In section 9.3.5.1 of the MISO-PJM JOA, each RTO agrees to assist in the preparation of a Coordinated System Plan.57 On an annual basis, the JRPC reviews each RTO’s annual regional plan.58 Each RTO’s annual regional plan is integrated into the RTOs’ Coordinated System Plan, including any market-based additions to the system infrastructure and jointly-identified Network Upgrades, as well as alternatives to Network Upgrades that were considered.59 Such annual review will include evaluation of transmission issues, including issues from each RTO’s market operations and annual planning processes or third parties.60 Such annual review will be administered by the JRPC.61

Consistent with the Final Rule’s requirement that coordination and joint evaluation take place in the same general timeframe as each region’s consideration of its regional

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53 Id. at section 9.3.2.
54 Id.
55 Id. at section 9.3.5.2(a)(i).
56 MISO-PJM JOA at section 9.3.5.2(a)(i).
57 Consistent with the requirement that neighboring transmission planning regions “harmonize differences in the data, models, assumptions, planning horizons and criteria used to study a proposed transmission project,” the RTOs propose revisions to section 9.3.5.2(a)(vi) that provide for the parties to use planning models that are developed in accordance with procedures to be established by the JRPC. The JRPC will develop joint study models consistent with the models. See Order No. 1000 at P 437.
58 See MISO-PJM JOA at section 9.1.1.1(a).
59 Id. at section 9.3.5.1.
60 Id. at section 9.3.5.2(a)(i).
61 See id. at section 9.1.1.1.
transmission plan, the scheduling of such annual review will take into consideration each RTO’s planning cycle in order to provide a meaningful opportunity to review and use such information in the regional transmission planning process. This is consistent with the Commission’s (i) requirement that both regions jointly evaluate interregional projects in the same general timeframe and (ii) preference that RTOs be permitted to develop appropriate timing arrangements with their neighbors. The Coordinated System Plan will also identify actions to resolve any cross-border impacts and describe the results of the joint transmission analysis, as well as provide an explanation, if necessary, of the procedures, methodologies and business rules applied in preparing and completing the analysis.

Secondly, following the annual review, the JRPC will provide a minimum of 60 days advance notice to stakeholders of an IPSAC meeting scheduled to review the issues identified during the annual review. In advance of the IPSAC meeting, the JRPC will solicit stakeholder consideration of identified transmission issues and supporting analysis at the IPSAC meeting. Following the IPSAC meeting, the JRPC will take into consideration the input received from the IPSAC to determine whether or not there is a need to perform a coordinated system plan study.

A coordinated system plan study will be initiated if (i) each RTO in the JRPC votes in favor of performing a coordinated system plan study; or (ii) after two consecutive years during which a coordinated system plan study has not been conducted, one RTO votes in favor of performing a coordinated system plan study. The JRPC will inform the IPSAC of its decision whether or not to initiate a coordinated system plan study. If a study is to be conducted, the JRPC will determine a mutually agreed to start date taking into consideration each RTO’s regional planning cycles.

Section 9.3.5.2(b) of the MISO-PJM JOA sets forth a detailed Coordinated System Plan study process. Specifically, the RTOs propose to revise this process to provide that: (i) each RTO will be responsible to provide the technical support necessary to complete the

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62 See Order No. 1000 at P 438.
63 See MISO-PJM JOA at section 9.3.5.2(a)(i).
64 See Order No. 1000 at P 439.
65 Id.
66 See MISO-PJM JOA at section 9.3.5.1.(c).
67 Id. at section 9.3.5.2(a)(i).
68 Id.
69 See id. at sections 9.1.1.1(b) and 9.3.5.2(a)(ii).
70 Id. at section 9.3.5.2(a)(ii).
71 Id.
72 Id. at section 9.3.5.2(a)(iii).
analysis for the study – responsibility for the compiling final study report will be alternated between the RTOs; \(^{73}\) (ii) the scope and procedure for the study will be developed by the JRPC; \(^{74}\) (iii) the study scope will include evaluations of issues identified and evaluated by the JRPC and the IPSAC at the annual issues meeting in order to further evaluate potential solutions; \(^{75}\) (iv) the study scope and assumptions will be documented and submitted to the IPSAC for review and comment; \(^{76}\) (v) the planning models will be developed pursuant to procedures established by the JRPC that are consistent with the models and assumptions used in each RTO’s most recently completed regional planning cycle; \(^{77}\) (vi) models will be available for stakeholder review and feedback subject to confidentiality and CEII requirements; \(^{78}\) (vii) the schedule will factor in IPSAC review and input at all stages of the study, including the development of potential solutions; \(^{79}\) and (viii) transmission solutions identified in the study process will be included in the Coordinated System Plan. \(^{80}\)

Following completion of the study, the JRPC will issue a report documenting the study including details such as the issues evaluated, the studies performed, solutions considered and, if applicable, the recommended cross-border projects with associated cost allocations. \(^{81}\) Such report will be provided to the IPSAC for review and comment. \(^{82}\) The final Coordinated System Plan report will be posted each on the RTO’s websites. \(^{83}\)

The final Coordinated System Plan study, including cross border projects approved for cost allocation purposes, will be reviewed by each RTO in the context of its regional planning process. \(^{84}\) Transmission plans identified to resolve problems will be included in the RTOs’ respective regional plans and presented to the respective RTO Boards for approval and implementation under each RTO’s procedures for approval. \(^{85}\) The MISO-PJM JOA provides for an expedited approval process for upgrades identified as

\(^{73}\) Id. at section 9.3.5.2(b)(i).

\(^{74}\) Id. at section 9.3.5.2(b)(ii).

\(^{75}\) Id.

\(^{76}\) Id. at sections 9.3.5.2(b)(v) and (vi).

\(^{77}\) Id. at section 9.3.5.2(b)(vi).

\(^{78}\) Id.

\(^{79}\) Id. at section 9.3.5.2(b)(vii).

\(^{80}\) Id. at section 9.3.5.2(b)(viii).

\(^{81}\) Id. at section 9.3.5.2(b)(ix).

\(^{82}\) Id.

\(^{83}\) Id.

\(^{84}\) MISO-PJM JOA at section 9.3.5.2(b)(x).

\(^{85}\) Id.
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critical.\textsuperscript{86} The JRPC will inform the IPSAC of the determinations rendered by each party’s review of the recommended cross-border projects approved for cost allocation purposes.\textsuperscript{87}

B. The JOA Meets the Order No. 1000 Requirements Regarding Data Exchange and Transparency

In addition to coordination and joint evaluation, which “embody the purpose of interregional transmission coordination,” the Commission found in Order No. 1000 that data exchange and transparency are “part of the procedures through which effective interregional coordination is implemented.”\textsuperscript{88}

1. Procedures for Annual Exchange of Data and Information

Order No. 1000 requires that each transmission provider adopt interregional transmission coordination procedures that provide for the exchange of planning data and information at least annually.\textsuperscript{89} In order to comply, transmission providers must do more than simply commit to share their regional transmission plans and other transmission planning information.\textsuperscript{90} Rather, the RTOs must clearly describe the procedures that will be used to exchange planning data and information, such as the type and frequency of meetings that are appropriate for and will accommodate each neighboring region’s planning cycles.\textsuperscript{91}

Consistent with the Final Rule, the proposed revisions to section 9.2 of the MISO-PJM JOA require that certain data and information be exchanged annually.\textsuperscript{92} Additionally, the RTOs propose to revise this section to separate out the requirements for annual data and information exchange\textsuperscript{93} and the data and information that will be exchanged upon request.\textsuperscript{94} Section 9.2.1 also describes the specific data and information that will be exchanged on an annual basis, the timing for the exchange, the models and format to be provided and the requirements for exchange of data compiled through other multi-regional modeling efforts. Section 9.2.2 provides the specifics for timely providing such data and the specific data and information that may be exchanged upon request.

\begin{itemize}
  \item \textsuperscript{86} \textit{Id.}
  \item \textsuperscript{87} \textit{Id.}
  \item \textsuperscript{88} Order No.1000 at P 394.
  \item \textsuperscript{89} \textit{See id.} at P 345, 454.
  \item \textsuperscript{90} \textit{See id.} at P 398.
  \item \textsuperscript{91} \textit{See id.} at P 455.
  \item \textsuperscript{92} \textit{See id.} at section 9.2.1.
  \item \textsuperscript{93} \textit{See MISO-PJM JOA} at section 9.2.1.
  \item \textsuperscript{94} \textit{See id.} at section 9.2.2.
\end{itemize}
The process used to exchange data provides that the JRPC is responsible for establishing a schedule for the rotation of responsibility for data management, coordination of stakeholder meetings, coordination of analysis activities, report preparation and other activities it deems appropriate. In addition, section 9.2 of the MISO-PJM JOA includes proposed revisions regarding the exchange of data and information that each RTO is required to share on an annual basis:

- Power flow models for projects system conditions for up to a 10 year planning horizon that include planned generation development and retirements, planned transmission faculties and seasonal load projects;
- System stability models with detailed dynamic modeling of generators and other active elements;
- Production cost models for projected system conditions for the planning horizon that includes generation and load forecasts and planned transmission facilities;
- Assumptions used in the development of power flow, stability and production cost models; and
- Contingency lists for use in power flow, stability and production cost analyses.

As further described in section 9.2, (i) the models will be consistent with those used in each RTO’s planning processes; (ii) the format used will be agreed upon by the RTOs; and (iii) the RTOs can use “best available information.” As agreed to by the RTOs, data compiled through other multi-regional modeling efforts can be used to satisfy the data exchange requirements. Unless the RTOs agree otherwise, the annual data exchange will be completed during the first calendar quarter of the year.

In addition, each RTO will provide the other with the following data and information upon request:

- Any changes to data previously exchanged in accordance with section 9.2.1 of the MISO-PJM JOA;
- Short circuit models for transmission systems that are relevant to the coordination of transmission planning between the RTOs;
- Each RTO’s regional plan, any long-term or short-term reliability assessment documents produced by each RTO, as well as the time of each planning enhancement and the estimated in-service date;
- Status update of expansion studies;

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95 Id. at section 9.1.1.1(h).
96 Id. at section 9.2.1.
97 Id.
• Identification and status of interconnection and long-term firm transmission service requests received and included in associated studies;
• Transmission system maps (bulk transmission system and relevant lower voltage transmission system maps) in electronic and hard copy format; and
• Such other data and information as needed by each RTO to plan its own system accurately and reliably and to assess impacts of conditions existing on the neighboring system.\(^98\)

Order No. 1000 clarified that transmission providers must do more than simply commit to share their regional transmission plans and other transmission planning information.\(^99\) As proposed, these additions to the RTOs’ current processes clearly demonstrate a commitment to share the information necessary to engage in coordinated system planning. Such revisions detail the specific information that will be made available as well as how such information will be exchanged.

2. The JOA Meets the Order No. 1000 Requirements for Transparency through Maintenance of Websites or E-mail Lists

Order No. 1000 requires transmission providers to maintain a website or email list for communications relative to the interregional transmission coordination procedures between the RTOs.\(^100\) Such information may be maintained on an existing transmission provider’s website.\(^101\) Regardless, the information must be posted so that stakeholders are able to distinguish between information related to the transmission provider’s regional and its interregional transmission coordination transmission planning.\(^102\)

Consistent with this requirement, the RTOs propose to amend the MISO-PJM JOA to add section 9.1.1.3 to clarify that each RTO will provide its own website for communication of information related to interregional transmission coordination between the RTOs. The JRPC is responsible for coordinating with the RTOs to ensure that all information and documents posted on each RTO’s website is accurate and consistent. Section 9.1.1.3 also details the minimum information that must be posted on such websites. Specifically, each website must contain (i) a link to the MISO-PJM JOA; (ii) notices of scheduled IPSAC meetings; (iii) links to materials for the IPSAC meetings; and (iv) documents related to the Coordinated System Plan studies.

\(^98\) Id.
\(^99\) See Order No. 1000 at P 398.
\(^100\) See id. at P 458.
\(^101\) See id.
\(^102\) See id.
Additionally, the Commission has found that stakeholder participation is an important component in interregional transmission coordination.\(^{103}\) The Commission stated, however, that the Final Rule does not require that interregional coordination procedures satisfy the Order No. 890 local planning principles or the Order No. 1000 regional planning principles.\(^{104}\) Rather, the Final Rule requires that transmission providers make transparent the analyses undertaken and determinations reached between the RTOs in the identification and evaluation of interregional facilities.\(^{105}\)

As detailed above at section III.A.1, through the IPSAC, stakeholders are provided numerous opportunities to review and submit input into the coordinated system planning process.\(^{106}\) Specifically, prior to the annual IPSAC meeting, stakeholders are given 60 days advance notice of the annual IPSAC meeting. During the 60-day period, stakeholders are given an opportunity to review the transmission issues identified by the JRPC as a result of its evaluation of each RTO’s annual regional planning report.\(^{107}\) In addition, stakeholders may identify and submit transmission issues and supporting analysis for review and consideration by the IPSAC and JRPC no later than 30 days prior to the IPSAC meeting.\(^{108}\) The Coordinated System Plan is not finalized until the IPSAC is afforded an opportunity to review and comment.\(^{109}\) Following the annual IPSAC meeting and based on input provided during the IPSAC meeting, the JRPC commits to inform the stakeholders whether or not it will initiate a Coordinated System Plan study.\(^{110}\) The Coordinated System Planning study schedule proposes to factor in time for IPSAC review and provide input at all stages of the study process, including the development of potential solutions.\(^{111}\) Additionally, the study scope, assumptions and proposed models used for the study will be submitted to the stakeholders for review and input.\(^{112}\) Thus, the RTOs propose revisions that are intended to meet the requirements of Order No. 1000 by providing stakeholders with an open and transparent process, as well as the opportunity to provide meaningful input into the coordinated system planning process that will afford them numerous opportunities to participate at every stage of the process.

\(^{103}\) See id. at P 465.

\(^{104}\) See id.

\(^{105}\) See Order No. 1000 at P 465.

\(^{106}\) See, e.g., MISO-PJM JOA at sections 9.1.2, 9.3.5.1, 9.3.5.2(a)(ii), 9.3.5.2(b)(iv), 9.3.5.2(b)(vi), 9.3.5.2(b)(vii), 9.3.5.2(b)(ix).

\(^{107}\) See id. at section 9.3.5.2(a)(i).

\(^{108}\) Id.

\(^{109}\) Id. at section 9.3.5.1.

\(^{110}\) See id. at section 9.3.5.2(a)(ii).

\(^{111}\) See id. at section 9.3.5.2(b)(vii).

\(^{112}\) See MISO-PJM JOA at sections 9.3.5.2(b)(ii), (vi).
C. Interregional Cost Allocation

1. Cross-Border Market Efficiency Projects

   (a) Cross-Border Market Efficiency Projects Satisfy the Interregional Cost Allocation Requirements of Order No. 1000

MISO, the PJM Transmission Owners, and the MISO Transmission Owners agree that CBMEPs satisfy the six interregional cost allocation principles set forth in Order No. 1000.\textsuperscript{113} As a result, MISO requests that the Commission approve the use of CBMEPs as compliant with the interregional cost allocation requirements of Order No. 1000 as between MISO and PJM.

   (b) Description of Cross-Border Market Efficiency Projects

For a project to qualify as a CBMEP, it must meet the criteria of section 9.4.3.1.2 of the MISO-PJM JOA. Specifically, CBMEPs must: (i) have an estimated Project Cost of $20,000,000 or greater; (ii) be evaluated as part of a Coordinated System Plan or joint study process; (iii) meet the threshold benefit to cost ratio as prescribed under the terms of, and using the benefit and cost measures prescribed under section 9.4.3.1.2.1 of the MISO-PJM JOA; (iv) qualify as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualify as Market Efficiency Project (“MEP”) (formerly called a Regionally Beneficial Project) under the terms of Attachment FF of the MISO Tariff; and (v) address one or more constraints for which at least one dispatchable generator in the adjacent market has a Generation-to-Load Distribution Factor (“GLDF”) of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.\textsuperscript{114}

Interregional cost allocation of CBMEPs depends on whether the project in question meets the benefits-to-costs ratio threshold defined by the JOA.\textsuperscript{115} The benefits-to-cost ratio is currently 1.25 to 1.\textsuperscript{116} The costs component of this calculation is the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the CBMEP are determined from the estimated CBMEP installed costs and the fixed charge rate applicable to the constructing transmission owner(s).\textsuperscript{117} The benefit metric used in the benefits-to-cost ratio is calculated by weighting the Adjusted Production Cost (“APC”) benefit, \textit{i.e.} the change in APC with and without the incorporation of the project in

\textsuperscript{113} See Order No. 1000 at P 578, \textit{et seq.}

\textsuperscript{114} See MISO-PJM JOA at section 9.4.3.1.2.

\textsuperscript{115} See \textit{id.} at section 9.4.3.1.2.1.b.

\textsuperscript{116} See \textit{id.}

\textsuperscript{117} See \textit{id.}
question, by 70 percent and the Net Load Payment ("NLP") benefit, i.e. the change in NLP with and without the incorporation of the project in question, by 30 percent. As stated in the JOA:

The APC for each RTO represents each RTO’s production costs adjusted for interchange purchases and sales. For each simulation hour in which an RTO is selling interchange, the APC shall be calculated by multiplying the interchange sales MW times the RTO’s generation-weighted LMP and then subtracting this value from the RTO’s production cost. For each simulation hour in which an RTO is purchasing interchange, the APC shall be calculated by multiplying the interchange purchase MW times the RTO’s load-weighted LMP and then adding this value to the RTO’s production cost.118

Further:

The NLP benefit for each RTO represents each RTO’s gross load payment minus the estimated value of congestion-hedging transmission rights in each RTO. The NLP shall be calculated by multiplying the LMP at each modeled load bus in the RTO by the load (in MW) at the bus, for each simulation hour (load LMP * load (in MW)), and then subtracting from that product the estimated value of congestion-hedging transmission rights for that hour. For each simulation hour, the value of an RTO’s transmission rights shall be calculated by subtracting the RTO generation-weighted LMP from the RTO load-weighted LMP and then multiplying this difference times the lower of the RTO’s total generation MW level or the RTO’s total load MW level.119

The benefit metric is calculated using the above inputs for each year of the simulation being run for the proposed project, with the annual benefit of the project being the sum of the benefit values for MISO and PJM.120 The total project benefit is then determined by calculating the present value of annual benefits for at least the first ten years of project life after the projected in-service year, with a maximum planning horizon of 20 years from the current year.

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118 Id. at section 9.4.3.1.2.1.a
119 Id.
120 See id. at section 9.4.3.1.2.1.b.
A proposed transmission project that meets all of the requisite CBMEP criteria of section 9.4.3.1.2 of the JOA is eligible for interregional cost allocation. Costs of these projects are allocated between MISO and PJM in proportion to the net present value of the total benefits calculated for each RTO.\footnote{See id. at section 9.4.3.2.2.}

As noted, CBMEPs must also qualify as MEPs. Pursuant to Attachment FF of the Tariff, MEPs are 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 Appendix B, Section VII of the ISO Agreement after June 16, 2005,\footnote{See Appendix B, Section VII of the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-stock Corporation (“Transmission Owners Agreement”) (“To fulfill their roles in the collaborative process for the development of the Midwest ISO Plan, the Owners shall develop expansion plans for their transmission facilities while taking into consideration the needs of (i) connected loads, including load growth, (ii) new customers and new generation sources within the Owner’s system, and (iii) known transmission service requests . . . the Midwest ISO shall develop a streamlined approval process for reviewing and approving projects proposed by the Owners so that decisions will be provided to the Owner within thirty (30) days of the projects submittal to the Midwest ISO unless a longer review period is mutually agreed upon”).} applying the factors set forth in Section I.A. of Attachment FF;\footnote{These factors include signing the Transmission Owners Agreement, and, within a reasonable period of time: (1) turning over functional control of transmission facilities to MISO and (2) taking service under the Tariff for all load that is physically located within the geographic area comprising MISO’s Transmission System.} (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 100kV 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 benefit-to-cost ratio threshold of 1.25 or greater, or that otherwise are needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the 345 kV or higher facilities of the project; (v) that are not determined to be Multi Value Projects ("MVPs");\footnote{Pursuant to Attachment FF, an MVP is one or more Network Upgrades that address a common set of Transmission Issues and satisfy the conditions listed in Sections II.C.1, II.C.2, and II.C.3 of Attachment FF.} and (vi) that are found to have regional benefits under the criteria set forth in Attachment FF.\footnote{These criteria require that MISO employ multiple future scenarios and multi-year analysis including sensitivity analyses guided by input from the Planning Advisory Committee to evaluate the anticipated benefits of a proposed MEP in order to determine if such a project meets the criteria for inclusion in the regional plan as an MEP eligible for regional cost sharing. Sensitivity analyses include, among other factors, consideration of: (i) variations in amount, type, and location of future generation supplies as dictated by future scenarios developed with stakeholder input and guidance; (ii) alternative transmission}
(c) Compliance with Order No. 1000’s Six Interregional Cost Allocation Principles

In Order No. 1000, the Commission directed public utility transmission providers in a planning region to have one or more common methods for allocating costs of new interregional transmission facilities among the beneficiaries of those facilities in the neighboring planning regions where the facilities are situated. Further, the Commission required that the method or methods developed for allocating costs of new interregional transmission facilities must be consistent with the six interregional cost allocation principles adopted in the Final Order.

MISO submits the CBMEP project type, which was first adopted pursuant to the Commission’s direction in November 2009, as its method for allocating costs of new interregional facilities between MISO and PJM. In light of previous Commission precedent and as further described below, the CBMEP project type is a previously accepted cost allocation method for new interregional transmission facilities that satisfies the six interregional cost allocation principles set forth in Order No. 1000. MISO therefore requests the Commission to approve the CBMEP proposal as compliant with the interregional cost allocation requirements of Order No. 1000 as between MISO and PJM.

i. Interregional Cost Allocation Principle 1: Costs Allocated Roughly Commensurate with Benefits

As set forth in Order No. 1000, the first interregional cost allocation principle is as follows:

The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, proposals; (iii) impacts of variations in load growth; and (iv) effects of demand response resources on transmission benefits. See section II.B.1 of Attachment FF.

126 See Order No. 1000 at P 578.
127 See id.
128 CBMEP Order at P 26.
production cost savings and congestion relief, and/or Public Policy Requirements.\textsuperscript{129}

Further, the Commission stated in Order No. 1000-A that for a cost allocation method to be accepted by the Commission as Order No. 1000-compliant, it “will have to clearly and definitively specify the benefits and the class of beneficiaries.”\textsuperscript{130}

Pursuant to the MISO-PJM JOA, CBMEP costs are allocated to beneficiaries in MISO and PJM in a manner that is at least roughly commensurate with the estimated benefits of these projects. As an initial matter, the Commission has previously determined that MISO’s and PJM’s proposed benefit formula for the cost allocation of CBMEPs is “a just and reasonable method of allocating costs[..]”\textsuperscript{131} In addition, like MEPs, CBMEPs are focused on addressing congestion relief and may also have beneficial reliability impacts. In addition, the MISO-PJM JOA ensures that the allocation of costs of CBMEPs between MISO and PJM is roughly commensurate with the benefits created by these projects by allocating costs in proportion to the net present value of the total benefits calculated for each RTO. Thus, each RTO is allocated CBMEP costs that directly correspond to the benefits calculated for that RTO derived from the CBMEP in question. As described supra in section III.C.1(b), the benefit metric is calculated for each RTO using the APC and NLP benefit metrics as inputs, which, in combination with the 1.25 to 1 benefits-to-costs threshold and the requirement that the CBMEP address constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater, ensures that each RTO’s benefit in terms of production cost savings and congestion relief is large enough to justify the project. As a result, the MISO-PJM JOA clearly defines the benefits and beneficiaries of CBMEPs, and the current cost allocation of new CBMEPs is, at a minimum, roughly commensurate with the estimated benefits provided by these facilities.

ii. Interregional Cost Allocation Principle 2: No Involuntary Cost Allocation to Non-Beneficiaries

As set forth in Order No. 1000, the second interregional cost allocation principle is as follows:

A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that transmission facility.\textsuperscript{132}

\textsuperscript{129} Order No. 1000 at P 622.
\textsuperscript{130} Order No. 1000-A at P 678.
\textsuperscript{131} CBMEP Order at P 27.
\textsuperscript{132} Order No. 1000 at P 638.
CBMEEP costs cannot be allocated to either PJM or MISO without being selected in both regions’ transmission planning processes.\(^\text{133}\) The allocation to each JOA party of the cost of any CBMEEP located in that party’s region is based on the voluntary agreement of both MISO and PJM, and the outcome of benefit determination processes, under the JOA. Under this voluntary arrangement, both parties will participate in the parallel regional and interregional processing and approval of CBMEPs. The goal of the process, and the basis of such approval, is the determination of the regional and interregional benefits that the parties are expected to receive from proposed CBMEPs.

To be eligible for interregional cost allocation, a proposed CBMEEP needs to successfully undergo these regional and interregional processes. First, the proposed CBMEEP should go through the JOA’s joint interregional study and evaluation process,\(^\text{134}\) which will assess expected present or likely future benefits; and a resulting Coordinated System Plan study report must recommend the project for approval in the regional processes of both parties.\(^\text{135}\) Second, the project must be approved and included in both parties’ regional plans for purposes of regional and interregional cost allocation, at which point the Interregional Project will become part of a Coordinated System Plan.\(^\text{136}\) Accordingly, the allocation to MISO of a CBMEEP in its region, or to PJM of such a project in its region, is premised on their voluntary undertakings, and the determination of their respective benefits, under the JOA. As a result, allocation to MISO or PJM cannot occur under the MISO-PJM JOA unless they are a beneficiary of the CBMEEP.

Further, as MISO noted in its Regional Compliance Filing, the Commission has previously found that MISO’s transmission planning process is appropriately designed to reasonably identify and estimate the benefits expected from MEPS, as which CBMEPs must qualify.\(^\text{137}\) MEPS are planned based on “future scenarios,”\(^\text{138}\) and the MEP benefit metric was in fact recently renamed from “Weighted Gain/No Loss” to “Weighted Futures/No Loss,” stressing the future scenario analysis.\(^\text{139}\) Thus, by extension, CBMEPs also ensure that costs are not involuntarily allocated to those who receive no current or likely future benefits from these projects.

\(^\text{133}\) MISO-PJM JOA at section 9.3.5.2(b)(x).
\(^\text{134}\) Id. at section 9.3.5.2(b).
\(^\text{135}\) Id. at section 9.3.5.2(b)(ix).
\(^\text{136}\) Id. at section 9.3.5.2(b)(x).
\(^\text{138}\) Attachment FF at section II.B.1.
\(^\text{139}\) MEP Order at P 21-23 (“MISO considers alternative future scenarios in its planning analysis”).
iii. Interregional Cost Allocation Principle 3: Benefit-to-Cost Threshold Ratio

As set forth in Order No. 1000, the third interregional cost allocation principle is as follows:

If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.140

As allowed by the third interregional cost allocation principle, the MISO-PJM JOA uses a cost-benefit threshold of 1.25 for CBMEPs.141 In addition, in the context of MEPs, the Commission recently found that the MEP “fixed benefit-cost ratio of 1.25 is just and reasonable because it balances the economic uncertainty of transmission projects with the prospect of approving and constructing projects that provide benefits.”142 By extension, the same is true of the 1.25 benefit-to-cost ratio employed in the MISO-PJM JOA for CBMEPs. The CBMEP benefits-to-cost ratio under the MISO-PJM JOA, therefore, is compliant with the 1.25 threshold set by Order No. 1000.


As set forth in Order No. 1000, the fourth interregional cost allocation principle is as follows:

Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not

140 Order No. 1000 at P 646.
141 See MISO-PJM JOA at section 9.4.3.1.2.1.b.
142 MEP Order at P 32.
located. However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if the transmission providers in the regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located.”\textsuperscript{143}

As an initial matter, in Order No. 1000 the Commission explicitly recognized that MISO and PJM have already implemented a cross-border cost allocation method that permits them to allocate to one RTO the cost of a transmission facility that is physically located entirely within the other RTO.\textsuperscript{144} The Commission further stated that MISO and PJM had “developed their cross-border allocation method in response to Commission directives related to MISO and PJM’s intertwined configuration,” and therefore that “MISO and PJM are not required by this Final Rule to revise their existing cross-border allocation method in response to Cost Allocation Principle 4.”\textsuperscript{145} As a result, MISO and PJM have retained the current features of the MISO-PJM JOA that allow for interregional cost allocation where a CBMEP is entirely located in only one RTO but benefits the other region.

MISO further notes that, pursuant to Order No. 1000-A,\textsuperscript{146} any MISO Transmission Owner that withdraws from MISO will remain responsible for its share of the cost of any Interregional Project that is an MEP approved by MISO’s Board of Directors before the effective date of such Transmission Owner’s withdrawal, even if no portion of the MEP is located in the transmission planning area to which the Transmission Owner will transfer.\textsuperscript{147}

v. Interregional Cost Allocation Principle 5: Transparency of Method for Determining Benefits and Identifying Beneficiaries

As set forth in Order No. 1000, the fifth interregional cost allocation principle is as follows:

\textsuperscript{143} Order No. 1000 at P 657.
\textsuperscript{144} Id. at P 662.
\textsuperscript{145} Id.
\textsuperscript{146} Order No. 1000-A at P 714.
\textsuperscript{147} See MISO’s Transmission Owners Agreement at Article Five, Section II and Attachment FF at section III.A.2.f.
The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed interregional transmission facility. ¹⁴⁸

The CBMEP cost allocation process is compliant with Order No. 1000’s transparency requirement. First, as summarized earlier, the allocation and benefit determination methods for CBMEPs are duly specified in section 9.4.3.1.2.1 of the MISO-PJM JOA. Second, the cost allocation method described in section 9.4.3.1.2.1 is applied in the context of MISO’s Coordinated System Planning process, which means that stakeholders will have the opportunity to participate in the IPSAC throughout the planning process. This participation will allow stakeholders to review the documentation and details of each project’s justification. Third, the results of MISO’s and PJM’s analysis of project benefits will be appropriately documented in the report on the Coordinated System Plan study, and the resulting recommendations are embodied in the Coordinated System Plan, ¹⁴⁹ which MISO and PJM will post publicly on the interregional planning webpages on their respective websites. Thus, MISO’s CBMEP cost allocation method, application, and results are properly transparent.


As set forth in Order No. 1000, the sixth interregional cost allocation principle is as follows:

The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.”¹⁵⁰

As previously noted, MISO is proposing that the CBMEP project type be the sole method of interregional cost allocation for the purposes of Order No. 1000 between MISO and PJM. As described in greater detail in section III.C.2.(a).iii of this Filing, MISO proposes

¹⁴⁸ Order No. 1000 at P 668.
¹⁴⁹ See supra section III.A.3.
¹⁵⁰ Order No. 1000 at P 685.
to retain the CBBRP project type, but, as explained further below, not as an Order No. 1000 interregional project with interregional cost allocation that is approved by both regions with regional cost allocation.

2. **Cross-Border Baseline Reliability Projects**

   (a) **The Cost Allocation Rules for CBBRPs Should Be Modified to Be Consistent With the Cost Allocation of BRPs Under the MISO Tariff**

   i. **Description of Cross-Border Baseline Reliability Projects**

     The MISO-PJM JOA currently provides that to qualify as a CBBRP, a project must: (i) by agreement of the JRPC, be needed to efficiently meet applicable reliability criteria; (ii) be a baseline reliability project as defined under the MISO or PJM Tariffs; (iii) result in an allocation of Project Cost to the RTO in which the project is not constructed *(i.e., the cross-border RTO)* of at least $10,000,000; (iv) involve the cross-border RTO’s contribution of at least five percent (5%) of the total loading on the constrained facility, as determined based on the Coordinated System Plan power flow model; and (v) have an in-service date after December 31, 2007.

     Interregional allocation of CBBRP costs between MISO and PJM varies depending on whether the project addresses thermal constraints or non-thermal constraints. For thermal constraints, the MISO-PJM JOA designates the share of the Project Cost to be allocated to each RTO based on the relative contribution of the combined Load of MISO and PJM, respectively, to loading on the constrained facility requiring the need for the CBBRP. Contribution to the thermal constraint is calculated using DFAX analysis. For non-thermal constraints, the JRPC establishes an interface, which is comprised of a number of transmission facilities, to serve as a surrogate for cost allocation responsibility. Allocation of cost responsibility for the non-thermal constraint is then determined by applying the same procedures used for thermal constraints, i.e., using DFAX analysis, with the interface serving as a surrogate for the thermal constraint.

     As noted, to qualify as a CBBRP a transmission project must be a BRP pursuant to MISO’s Tariff. Per Attachment FF of MISO’s Tariff, BRPs are defined as follows:

     Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with

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151 MISO-PJM JOA at section 9.4.3.1.1.
152 See id. at section 9.4.3.2.1.a.
153 See id. at section 9.4.3.2.1.b.
154 See Attachment FF at section II.A.
applicable [NERC] reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region.\textsuperscript{155}

The March 22 Order, however, accepted, effective June 1, 2013, MISO’s proposal to modify the existing BRP cost allocation method to eliminate any cost sharing as between transmission pricing zones. Instead, MISO now allocates all BRP costs to the pricing zone where the BRP is located.\textsuperscript{156} Consequently, BRPs in MISO no longer involve any regional cost allocation.

\textbf{ii. Disagreement Between MISO and the PJM Transmission Owners}

Although MISO and the PJM Transmission Owners agree that CBMEPs satisfy the requirements of Order No. 1000 with regard to interregional cost allocation, they disagree on whether the JOA’s current cost allocation rules for CBBRPs should be retained by this compliance filing. Specifically, as further described below, MISO has determined that, in light of the elimination of any regional cost allocation component from BRPs, the JOA’s present rules for allocating CBBRP costs between MISO and PJM are not consistent with Order No. 1000’s requirements for interregional cost allocation, and the Commission’s earlier orders on the cost allocation of cross-border projects. The MISO Transmission Owners agree with MISO on this point. On the other hand, the PJM Transmission Owners consider the JOA’s existing CBBRP cost allocation rules consistent with Order No. 1000’s requirements.

As a result of their disagreement on this issue, MISO and the PJM Transmission Owners are submitting separate proposals regarding the allocation of CBBRP costs. MISO is proposing revisions to the MISO-PJM JOA under which only CBMEPs are eligible for Order No. 1000-compliant interregional cost allocation of projects approved in the RTOs’ regional plans for purposes of regional cost allocation, while the cost of CBBRPs will be shared (or not shared) based on whether the project is a tie-line as well as on whether neighboring Transmission Owners in MISO and PJM agree to share costs, as further described in section III.C.2.(a).iii below.

\textbf{iii. MISO’s Proposal}

As explained in the accompanying testimony of Jennifer Curran (at pages 12-13), MISO is proposing to remove the existing flow-based cost allocation mechanisms for CBBRPs, \textit{i.e.}, DFAX analysis, and instead to include provisions that would allow for cost sharing of CBBRPs that are tie-lines that interconnect to the transmission facilities of a MISO and PJM Transmission Owner, respectively, as well as potential cost sharing of

\textsuperscript{155} See id. at section II.A.1.

\textsuperscript{156} See March 22 Order at P 484.
CBBRPs that are not tie-lines. Although MISO proposes to retain the CBBRP project type in the MISO-PJM JOA, CBBRPs would not be eligible for Order No. 1000-compliant interregional cost allocation going forward as projects approved in the RTOs’ regional plans for purposes of regional cost allocation.

Specifically, MISO proposes to revise section 9.4.3.1.1 of the MISO-PJM JOA such that CBBRPs must meet the following criteria only:

(i) by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria; (ii) the project must be a baseline reliability project as defined under the Midwest ISO or PJM Tariffs.

MISO has removed the qualification criteria regarding project cost, in-service date, and contribution to loading. MISO further proposes to revise section 9.4.3.2.1, “Cost Allocation for Cross-Border Baseline Reliability Projects,” to state as follows:

a. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and interconnects to the transmission facilities of a Transmission Owner in MISO and the transmission facilities of a Transmission Owner in PJM, the ownership and responsibility to construct shall be based on the RTO boundaries between the connected Transmission Owners in each RTO, unless otherwise agreed to by such Transmission Owners. Each RTO shall recover the costs associated with the portion owned by their respective Transmission Owner(s) in accordance with the recovery provisions in the applicable Party’s OATT.

b. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and is located solely within the MISO RTO, the constructing MISO Transmission Owner(s) will work with the PJM Transmission Owner(s) that has/have a reliability-based need that the CBBRP described in this Section 9.4.2.1.b addresses to determine by mutual agreement whether all or a portion of the Network Upgrade Project Cost should be paid for by the PJM Transmission Owner(s). Absent such an agreement with the PJM Transmission Owner(s), the constructing MISO Transmission Owner(s) has/have the following options:

i. If the CBBRP is not needed to address a reliability issue within the MISO pricing zone(s) where it would be located, the constructing MISO Transmission Owner(s) may elect not to construct the project to address the PJM reliability issue.

ii. If the CBBRP is needed to address a reliability issue within the MISO pricing zone where it would be located, the constructing MISO Transmission Owner(s) may elect to construct the project as a
baseline reliability project as defined in the MISO tariff to address the MISO reliability issue.

iii. If the CBBRP is needed to address a reliability issue within the MISO pricing zone where it would be located, as an alternative to 9.4.3.2.1.b.ii, the constructing MISO Transmission Owner(s) has/have the option of working with MISO to identify an alternative Network Upgrade to address the reliability issue in the MISO pricing zone.

c. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and is located solely within the PJM RTO, the constructing PJM Transmission Owner(s) will work with the MISO Transmission Owner(s) that has/have a reliability-based need that the CBBRP described in this Section 9.4.3.2.1.c addresses to determine by mutual agreement whether all or a portion of the Network Upgrade Project Cost should be paid for by the MISO Transmission Owner(s). Absent such an agreement with the MISO Transmission Owner(s), the constructing PJM Transmission Owner(s) has/have the following options:

i. If the CBBRP is not needed to address a reliability issue within PJM, the constructing PJM Transmission Owner(s) may elect not to construct the project to address the MISO reliability issue.

ii. If the CBBRP is needed to address a reliability issue within PJM, the constructing PJM Transmission Owner(s) may elect to construct the project as a baseline reliability project as defined in the PJM tariff to address the PJM reliability issue.

iii. If the CBBRP is needed to address a reliability issue within PJM, as an alternative to 9.4.3.2.1.c.ii, the constructing PJM Transmission Owner(s) has/have the option of working with PJM to identify an alternative Network Upgrade to address the reliability issue in PJM.

Thus, in the case of tie-lines, the connected Transmission Owners in MISO and PJM respectively will have ownership and the responsibility to build the Network Upgrade unless otherwise agreed. For the share of the project cost incurred by any MISO Transmission Owner(s), MISO will recover those costs from the pricing zone(s) of Transmission Owner(s) in accordance with MISO’s Tariff, while PJM can allocate its share of the project cost pursuant to its tariff. For CBBRPs located only in one of the RTOs, the affected Transmission Owners will also coordinate on potential cost sharing. However, in the latter instance, if the affected neighboring Transmission Owners cannot come to agreement on cost sharing, the Transmission Owner(s) in whose pricing zone(s) the CBBRP would be constructed may decline to build the project if it is not needed to address a reliability issue located within the MISO pricing zone(s) where it would be
located; or, if the project is needed to address a reliability issue located within the pricing zone where it would be located, the Transmission Owner(s) in whose zone(s) the facility would be constructed may either elect to construct the project as a BRP or work with MISO or PJM, as necessary, to identify an alternative Network Upgrade to address the reliability issue.

As further described below, although MISO proposes to remove the JOA’s flow-based cost allocation mechanism for CBBRPs, coordination on reliability planning between PJM and MISO could nonetheless result in cross-border reliability-related projects that also qualify as CBMEPs. In these instances, such transmission projects will be cost shared as CBMEPs. However, MISO recognizes that some cross-border reliability projects may not qualify as CBMEPs. In these instances, section 9.4.3.2.1 would apply.

Regardless of whether a cross-border reliability project qualifies as a CBMEP, MISO and PJM will continue to coordinate and plan with regard to reliability issues.157 Pursuant to section 9.3.1 of the JOA, which is retained by this compliance filing, MISO and PJM commit to sharing information relating to single party planning, which must conform to applicable reliability requirements of each party, NERC, and applicable regional entities, as well as any applicable federal, state or provincial laws or regulations, on an ongoing basis as necessary for effective coordination between the RTOs. In addition, the Coordinated System Plan integrates each party’s respective transmission expansion plan, including any identified reliability-related Network Upgrades.158

(b) Rationales for MISO’s Proposal

MISO and the PJM Transmission Owners disagree on the question of whether CBBRPs should retain their existing cross-border cost allocation mechanism, and should be relied on for purposes of Order No. 1000 compliance. MISO proposes to rely solely on CBMEPs for purposes of compliance with Order No. 1000. As outlined below, there are several reasons supporting MISO’s proposal to rely on CBMEPs alone to meet Order No. 1000’s interregional requirements, and to address CBBRPs outside the context of interregional cost allocation.

i. Interregional Allocation of CBBRP Costs is Inconsistent with Order No. 1000’s Requirement That Interregional Projects be Included in Regional Plans for Purposes of Regional Cost Allocation

Order No. 1000 conditioned a potential interregional project’s eligibility for interregional cost allocation on the selection of the project in each of the relevant regional

157 See Tab D, Testimony of Jennifer Curran at 15-18 (“Curran Testimony”).
158 See MISO-PJM JOA at section 9.3.5.1.
transmission planning processes for the purposes of cost allocation. In Order No. 1000, the phrase “for purposes of cost allocation” refers to selection pursuant to a transmission planning region’s transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation. Thus, for a cross-border project between MISO and PJM to be eligible for cost allocation between them, it must be selected in both MISO’s and PJM’s respective transmission planning processes for the purposes of regional cost allocation. In addition, the Commission’s prior orders on the allocation of cross-border projects between MISO and PJM involved contexts where the cost of potential cross-border projects in MISO, i.e., MEPs and BRPs, were at least partly allocated regionally.

Since MISO’s BRPs no longer involve any regional cost allocation, and the JOA currently requires a CBBRP located in MISO to be a BRP under MISO’s Tariff, it is no longer possible for a BRP that is a potential CBBRP to be selected in MISO’s transmission planning process for the purposes of regional cost allocation. Specifically, the Commission approved MISO’s proposal to eliminate regional cost sharing for BRPs and to instead allocate costs for such projects to the pricing zone where the project is located. As a result, BRPs that were otherwise potential CBBRPs are no longer eligible for interregional cost allocation.

Throughout MISO’s and the PJM Transmission Owners’ discussions regarding Order No. 1000’s interregional cost allocation requirements, the PJM Transmission Owners have not been open to any of MISO’s proposed revisions to the JOA’s existing CBBRP cost allocation provisions to remove conflicts with MISO’s Tariff, as now revised. The PJM Transmission Owners instead assert that CBBRPs should be retained in the MISO-PJM JOA for the purposes of interregional cost allocation, even if MISO’s BRPs could no longer be included in MISO’s regional transmission plan for purposes of regional

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159 See, e.g., Order No. 1000 at P 582 (“An interregional transmission facility must be selected in both of the relevant regional transmission planning processes for purposes of cost allocation in order to be eligible for interregional cost allocation pursuant to a cost allocation method required under this Final Rule.”).

160 Id. at P 63.

161 MISO’s filing proposing the CBMEP project type included changes to section 9.4.3.4, which clarified that cost recovery of any share of cost of a border project allocated to either RTO would be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated. Docket No. ER05-6-108 (Jan. 28, 2009). See also, e.g., 113 FERC ¶ 61,194 at P 5; Counterflow Order at n. 21.

162 March 22 Order at P 484.

163 MISO-PJM JOA at section 9.4.3.1.1.

164 See March 22 Order at P 520.

165 Id. (“We find that, under the particular circumstance presented by MISO in this proceeding, assigning all of the costs of a Baseline Reliability Project to the pricing zone in which the project is located allocates costs roughly commensurate with the benefits that the project is expected to provide.”).
cost allocation. However, the PJM Transmission Owners have failed to cite or explain to MISO any portion of Order No. 1000 identifying any exception to the requirement that an interregional project be included in regional plans for purposes of regional cost allocation.

In its discussions with MISO on interregional compliance, the PJM Transmission Owners supported their proposed retention of the JOA’s current cost allocation rules for CBBRPs by pointing to section 9.4.3.4 of the JOA, which states the “cost recovery of any share of cost of a border project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.” However, this provision only addresses the allocation of each RTO’s share of CBBRP costs within each RTO after the CBBRP is determined to be eligible for interregional cost sharing. Given the elimination of any regional cost sharing of BRPs in MISO effective June 1, 2013,166 no MISO BRP can qualify as a CBBRP eligible for interregional cost allocation under Order No. 1000, because BRPs would not be included in MISO’s regional transmission plan for purposes of regional cost allocation.

ii. MISO’s Proposal is Consistent with the Cost Allocation of BRPs Under its Tariff

MISO’s proposal is consistent with the Commission-approved treatment of BRPs under the MISO Tariff. Specifically, as previously discussed, BRPs are currently allocated entirely to the pricing zone in which the BRP is located and are no longer regionally allocated. Moreover, as explained by Ms. Curran, to the extent that a project that otherwise qualifies as a BRP and also satisfies the criteria for an MEP it is appropriate to treat the project as an MEP rather than a BRP.167 For these reasons, it is appropriate to allocate the costs of projects that qualify only as BRPs locally, and to reserve regional cost allocation for MEPs and MVPs. The Commission endorsed this approach in the March 22 Order.

MISO notes that this change does not have any immediate or foreseeable impact on the implementation of the MISO-PJM JOA because, as explained by Ms. Curran, there has never been an identified CBBRP in the history of the MISO-PJM JOA, nor is one currently under consideration.168

For these reasons, it is appropriate to remove CBBRPs from eligibility for interregional cost allocation under Order No. 1000. Instead, MISO proposes that cost responsibility for CBBRPs be mainly based on geographic location, along with provisions to facilitate cost sharing agreements amongst affected Transmission Owners for these projects located in areas geographically different from the areas where identified reliability benefits are needed, as described previously in section III.C. 2.(a).iii.

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166 *Id.* at P 486.
167 *See* Curran Testimony at 6.
168 *See* id. at 5.
iii. Local Allocation of CBBRP Costs is Consistent with the Commission’s Rulings on Participant Funding

MISO’s proposal that (i) the cost of any tie-line CBBRPs be shared between the interconnecting Transmission Owners in MISO and PJM based on RTO boundaries unless otherwise agreed, and (ii) that non-tie-line CBBRPs be optionally shared amongst the constructing Transmission Owner and the neighboring Transmission Owner is also consistent with Order No. 1000’s determination that participant funding is permitted, but not as a regional or interregional cost allocation method.\footnote{See Order 1000 at P 723.} The Commission has clarified that “regions are free to negotiate interregional transmission arrangements that allow for the allocation of costs to beneficiaries that are not located in the same transmission planning region as any given interregional transmission facility.”\footnote{Id. at P 582.} Given that the current MISO-PJM JOA explicitly applies to reliability projects constructed in one RTO but which have a beneficial impact in the other RTO, MISO’s proposal for voluntary cost assignment of CBBRPs is also consistent with Order No. 1000. Further, the Commission has stated that its focus in parts of Order No. 1000 on transmission facilities selected in a regional transmission plan for purposes of cost allocation is not intended to disturb regional practices with regard to other transmission facilities that also may be in the regional transmission plan.\footnote{Id. at P 64.} MISO’s proposal is similarly consistent with this aspect of Order No. 1000.

IV. SUPPORTING DOCUMENTS

In addition to this Transmittal Letter, the following documents are being submitted with this filing:

Tab A-1 – Redlined Version of Existing JOA (deleting the existing Certificate of Concurrence and adding the entire text of the existing MISO-PJM JOA to the MISO Tariff)

Tab A-2 – Redlined Version of Revised JOA Provisions (proposing changes to the existing MISO-PJM JOA)

Tab B – Clean Version of Revised JOA Provisions

Tab C – List of Regional Stakeholder Meetings on Interregional Compliance Filing

Tab D – Testimony of Jennifer Curran
V. PROPOSED EFFECTIVE DATE AND REQUEST FOR EXTENDED COMMENT PERIOD

A. Requested Effective Date

MISO respectfully requests that the proposed MISO-PJM JOA revisions be made effective on January 1, 2014, if the Commission either:

(1) Finds, in its order on this filing and PJM’s contemporaneous filing, that the tariff revisions accepted by the March 22, 2013 order regarding MISO’s Order No. 1000 regional compliance filing in Docket No. ER13-187-000, and the tariff revisions accepted by the March 22, 2013 order regarding PJM’s Order No. 1000 regional compliance filing in Docket No. ER13-198-000, are sufficient for purposes of allowing MISO’s and PJM’s respective regional planning and cost allocation provisions to be implemented effectively in conjunction with the interregional coordination/planning process and cost allocation method proposed herein, without waiting for favorable Commission action on the further regional compliance filings that MISO and PJM are respectively due to submit by July 22, 2013; or

(2) Accepts by January 1, 2014, the key provisions of MISO’s and PJM’s respective further regional compliance filings due on July 22, 2013.

If any of these two circumstances is not present by January 1, 2014, then MISO alternatively requests an effective date of June 1, 2014. The above-described preconditions are necessary because the proposed interregional coordination/planning process and cost allocation method depend on the preceding or approximately concurrent implementation of MISO’s and PJM’s respective regional planning processes in accordance with the Commission’s requirements.

B. Request for Extended Comment Period

In addition, MISO respectfully requests that the Commission provide an extended period for parties to file comments on this filing until September 9, 2013. Given the complexity, extent, and importance of the changes proposed to the MISO-PJM JOA (and the other changes proposed by MISO), and the areas of disagreement with the PJM Transmission Owners, MISO believes an extended comment period is appropriate to permit all interested parties adequate opportunity to analyze and submit comments on the proposed changes to the MISO-PJM JOA.
VI. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to the following persons, who shall also be authorized to receive notice in this docket:

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VII. NOTICE AND SERVICE

MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, MISO Advisory Committee participants, as well as all state commissions within the Region, and the Organization of MISO States. In addition, the filing has been posted at https://www.misoenergy.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx, on MISO’s website, for other interested parties in this matter.
VIII. CONCLUSION

The Filing Parties respectfully request that the Commission accept this filing, and the proposed revisions to the MISO-PJM JOA, as compliant with the interregional coordination and cost allocation requirements of Order Nos. 1000, 1000-A and 1000-B, as discussed above.

Sincerely,

/s/ Matthew R. Dorsett
Matthew R. Dorsett
Attorney
Midcontinent Independent System Operator, Inc.

/s/ Daniel M. Malabonga
Daniel M. Malabonga
Jason R. Wool
Venable LLP

Attorneys for MISO

/s/ Brooksany Barrowes
Brooksany Barrowes
Baker Botts L.L.P.

Attorney for the
MISO Transmission Owners

/Attachments
TAB A-1

Redlined Version of Existing JOA
Rate Schedule 5 Midwest ISO-PJM Joint Operating Agreement Version: 1.0.0

Effective: 9/17/2010

Midwest Independent Transmission System Operator, Inc.

Joint Tariff Name: MISO JOA

Designated Filing Company (“DFC”): PJM Interconnection, L.L.C.

DFC Tariff Title: PJM Interconnection L.L.C.—Interregional Agreements

DFC Tariff Program: FERC Electric Tariff


Joint Operating Agreement

Between the

Midwest Independent Transmission System Operator, Inc.

And

PJM Interconnection, L.L.C.

(December 11, 2008)
Joint Operating Agreement

Between the

Midwest Independent Transmission System Operator, Inc.

And

PJM Interconnection, L.L.C.

ARTICLE I

RECITALS

This Joint Operating Agreement (“Agreement”) dated this 31st day of December, 2003, by and between PJM Interconnection, L.L.C. (“PJM”) a Delaware limited liability company having a place of business at 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403, and the Midwest Independent Transmission System Operator, Inc. (“Midwest ISO”), a Delaware non-stock corporation having a place of business at 701 City Center Drive, Carmel, Indiana 46032.

WHEREAS, PJM is the regional transmission organization that provides operating and reliability functions in portions of the mid-Atlantic and Midwest States. PJM also administers an open access tariff for transmission and related services on its grid, and independently operates markets for day-ahead, real-time energy, and financially firm transmission rights;

WHEREAS, the Midwest ISO is the regional transmission organization that provides operating and reliability functions in portions of the Midwest States and Canadian Provinces. The Midwest ISO administers an open access tariff for transmission and related services on its grid, and is developing processes and systems to operate markets to facilitate trading of day-ahead, real-time energy, and financially firm transmission rights;

WHEREAS, the Federal Energy Regulatory Commission has ordered each regional transmission organization to develop mechanisms to address inter-regional coordination;

WHEREAS, on February 12, 2003, the Parties entered into the Agreement Concerning Inter-regional Coordination, Including Development of Joint and Common Market ("Joint and Common Market Agreement"), which provides for the establishment of an Inter-RTO Steering Committee to facilitate development of the Joint and Common Market and resolution of seams issues between the Parties;
WHEREAS, certain other electric utilities will be integrated into the systems and markets PJM administers and controls, and it is recognized that such integration may result in changed flows on the systems of PJM and the Midwest ISO as they exist prior to such integration;

WHEREAS, in accordance with good utility practice and in accordance with the directives of the Federal Energy Regulatory Commission, the Parties seek to establish exchanges of information and establish or confirm other arrangements and protocols in furtherance of the reliability of their systems and efficient market operations, and to give effect to other matters required by the Federal Energy Regulatory Commission;

NOW, THEREFORE, for the consideration stated herein, and for other good and valuable consideration, including the Parties’ mutual reliance upon the covenants contained herein, the receipt of which hereby is acknowledged, PJM and the Midwest ISO hereby agree as follows:

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE II ABBREVIATIONS, ACRONYMS, AND DEFINITIONS Version: 0.0.0

Effective: 9/17/2010
2.1 Abbreviations and Acronyms

2.1.1 “AC”
AC shall mean alternating current.

2.1.2 “AFC”
AFC shall mean Available Flowgate Capability.

2.1.2.a “APC”
APC shall mean Adjusted Production Cost.

2.1.3 “ARR”
ARR shall mean Auction Revenue Rights.

2.1.4 “BA”
BA shall mean Balancing Authority.

2.1.5 “BAA”
BAA shall mean Balancing Authority Area.

2.1.5.a “CBBRP”
CBBRP shall mean Cross-Border Baseline Reliability Project.

2.1.5.b “CBMEP”
CBMEP shall mean Cross-Border Market Efficiency Project.

2.1.6 “CBM”
CBM shall mean Capacity Benefit Margin.

2.1.7 “CFR”
CFR shall mean Code of Federal Regulations.

2.1.8 “CIM”
CIM shall mean Common Information Model.

2.1.9 “DC”
DC shall mean direct current.

2.1.10 “DFAX”
DFAX shall mean transfer distribution factors.

2.1.11 “EHV”
EHV shall mean Extra High Voltage.
2.1.12 “EMS”
EMS shall mean the respective Energy Management Systems utilized by the Parties to manage the flow of energy within their RC Areas.

2.1.13 “ERAG”
ERAG shall mean the Eastern Interconnection Reliability Assessment Group that is charged with multi-regional modeling.

2.1.14 “FERC” (or “Commission”)
FERC shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

2.1.15 “FTR”
FTR shall mean financial transmission rights.

2.1.16 “GLDF”
GLDF shall mean Generation-to-Load Distribution Factor.

2.1.17 “ICCP”, “ISN” and “ICCP/ISN”
ICCP, ISN and ICCP/ISN shall mean those common communication protocols adopted to standardize information exchange.

2.1.18 “IDC”
IDC shall mean the NERC Interchange Distribution Calculator used for identifying and requesting congestion management relief.

2.1.19 “IPSAC”
IPSAC shall mean Inter-regional Planning Stakeholder Advisory Committee.

2.1.20 “IROL”
IROL shall mean Interconnection Reliability Operating Limit.

2.1.21 “ISC”
ISC shall mean the Inter-RTO Steering Committee.

2.1.22 “JRPC”
JRPC shall mean the Joint RTO Planning Committee.

2.1.23 “kV”
kV shall mean kilovolt of electric potential.

2.1.24 “LBA”
LBA shall mean Local Balancing Authority.

2.1.25 “LBAA”
LBAA shall mean Local Balancing Authority Area.
2.1.26 “LMP”
LMP shall mean Locational Marginal Price.

2.1.27 “MMWG”
MMWG shall mean the Multi-regional Modeling Working Group.

2.1.28 “MTEP”
MTEP shall mean Midwest ISO Transmission Expansion Plan.

2.1.29 “MVAR”
MVAR shall mean megavolt amp of reactive power.

2.1.30 “MW”
MW shall mean megawatt of real power.

2.1.31 “MWh”
MWh shall mean megawatt hour of energy.

2.1.32 “NAESB”
NAESB shall mean North American Energy Standards Board or its successor organization.

2.1.33 “NERC”
NERC shall mean the North American Electricity Reliability Corporation or its successor organization.

2.1.33a “NLP”
NLP shall mean Net Load Payment.

2.1.34 “NSI”
NSI shall mean net scheduled interchange.

2.1.35 “OASIS”
OASIS shall mean the Open Access Same-Time Information System required by FERC for the posting of market and transmission data on the Internet.

2.1.36 “OATT”
OATT shall mean the applicable open access transmission tariff.

2.1.37 “OTDF”
OTDF shall mean Outage Transfer Distribution Factor.

2.1.38 “PMAX”
PMAX shall mean the maximum generator real power output reported in MWs on a seasonal basis.
2.1.39 “PMIN”
PMIN shall mean the minimum generator real power output reported in MWs on a seasonal basis.

2.1.40 “PSS/E”
PSS/E shall mean Power System Simulator for Engineering.

2.1.41 “PTDF”
PTDF shall mean Power Transfer Distribution Factor.

2.1.42 “QMAX”
QMAX shall mean the maximum generator reactive power output reported in MVARs at full real power output of the unit.

2.1.43 “QMIN”
QMIN shall mean the minimum generator reactive power output reported in MVARs at full real power output of the unit.

2.1.44 “RC”
RC shall mean Reliability Coordinator.

2.1.45 “RCF”
RCF shall mean Reciprocal Coordinated Flowgate.

2.1.46 “RCIS”
RCIS shall mean the Reliability Coordinator Information System.

2.1.47 “RTEP”
RTEP shall mean PJM Regional Transmission Expansion Plan.

2.1.48 “RTO”
RTO shall mean regional transmission organization.

2.1.49 “SCADA”
SCADA shall mean Supervisory Control and Data Acquisition.

2.1.50 “SDX System”
SDX System shall mean the system used by NERC to exchange system data.

2.1.51 “SOL”
SOL shall mean System Operating Limit.

2.1.52 “TCUL”
TCUL shall mean tap-changing-under-load.
2.1.53 “TFC”  
TFC shall mean Total Flowgate Capability.

2.1.54 “TLR”  
TLR shall mean Transmission Loading Relief.

2.1.55 “TOP”  
TOP shall mean Transmission Operator.

2.1.56 “TRM”  
TRM shall mean Transmission Reliability Margin.

2.1.57 “UDS”  
UDS shall mean Unit Dispatch Systems.

2.1.58 “VAR”  
VAR shall mean volt ampere reactive.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
Section 2.2 Definitions Version: 0.0.0 Effective: 6/16/2011

2.2 Definitions.
Any undefined, capitalized terms used in this Agreement shall have the meaning given under industry custom and, where applicable, in accordance with good utility practices.

2.2.1 “a & b multipliers”
“a & b Multipliers” shall mean the multipliers that are applied to TRM in the planning horizon and in the operating horizon to determine non-firm AFC. The “a” multiplier is applied to TRM in the planning horizon to determine non-firm AFC. The “b” multiplier is applied to TRM in the operating horizon to determine non-firm AFC. The “a & b” multipliers can vary between 0 and 1, inclusive. They are determined by individual transmission providers based on network reliability considerations.

2.2.2 “Affected System”
Affected System shall mean the electric system of the Party other than the Party to which a request for interconnection or long-term firm delivery service is made and that may be affected by the proposed service.

2.2.3 “Agreement”
Agreement shall mean this document, as amended from time to time, including all attachments, appendices, and schedules.

2.2.4 “American Electric Power”
American Electric Power shall mean the American Electric Power Company.

2.2.5 “Available Flowgate Capability”
Available Flowgate Capability shall mean the rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

2.2.6 “Balancing Authority”
Balancing Authority shall mean the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real-time. For Midwest ISO references to a BA may be applicable to a BA and/or an LBA.

2.2.7 “Balancing Authority Area”
Balancing Authority Area shall mean the collection of generation, transmission, and loads within the metered boundaries of the BA. The BA maintains load-resource balance
within this area. For Midwest ISO references to a BAA may be applicable to a BAA and/or an LBAA.

2.2.8 “Bulk Electric System”
Bulk Electric System shall mean the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving load with only one transmission source are generally not included in this definition.

2.2.9 “Commonwealth Edison”
Commonwealth Edison shall mean the Commonwealth Edison Company.

2.2.10 “Confidential Information”
Confidential Information shall have the meaning stated in Section 18.1.1.

2.2.11 “Congestion Management Process”
Congestion Management Process means that document incorporated herein as Attachment 2 to this Agreement hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.12 “Coordinated Flowgate”
Coordinated Flowgate shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of the attached document entitled “Congestion Management Process.” For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion Management portion of the Congestion Management Process (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a Third Party.

2.2.13 “Coordinated Operations”
Coordinated Operations means all activities that will be undertaken by the Parties pursuant to this Agreement.

2.2.14 “Coordinated System Plan”
Coordinated System Plan shall have the meaning stated in Section 9.3.5.

2.2.14.a “Cross-Border Baseline Reliability Project”
Cross-Border baseline Reliability Project shall have the meaning stated in Section 9.4.3.1.1.

2.2.14.b “Cross-Border Market Efficiency Project”
Cross-Border Market Efficiency Project shall have the meaning stated in Section 9.4.3.1.2.

2.2.15 “Cross-Border Grandfathered Projects”
Cross Border Grandfathered Projects shall mean the Cross-Border Grandfathered Projects document incorporated herein as Attachment 4 to this Agreement, hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.16 “Economic Dispatch”
Economic Dispatch shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

2.2.17 “Effective Date”
Effective Date shall have the meaning stated in Section 12.1.

2.2.18 “Emergency Energy Transactions”
Emergency Energy Transactions shall mean the Emergency Energy Transactions document incorporated herein as Attachment 5 to this Agreement, hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.19 “Extra High Voltage”
Extra High Voltage shall mean 230 kV facilities and above stations with voltage regulating capabilities.

2.2.20 “Facilities Study”
Facilities Study shall mean a study conducted by the Transmission Service Provider, or its agent, for the interconnection customer to determine a list of facilities, the cost of those facilities, and the time required to interconnect a generating facility with the transmission system or enable the sale of firm transmission service.

2.2.21 “Feasibility Study”
Feasibility Study shall mean a preliminary evaluation of the system impact of interconnecting a generating facility to the transmission system or the initial review of a transmission service request.

2.2.22 “Firm Flow”
Firm Flow shall mean the estimated impacts of Firm Transmission Service on a particular Coordinated Flowgate.

2.2.23 “Firm Flow Limit”
Firm Flow Limit shall mean the maximum value of Firm Flows an entity can have on a Coordinated Flowgate, based on procedures defined in Sections 4 and 5 of the Congestion Management Process.

2.2.24 “Flowgate”
Flowgate shall mean a representative modeling of facilities or groups of facilities that may act as significant constraint points on the regional system.

2.2.25 “Hold Harmless Issues”
Hold Harmless Issues shall have the meaning given in Section 4.3.
2.2.26 “Governing Documents”
Governing Documents shall mean the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Reliability Assurance Agreement, the Midwest ISO Open Access Transmission and Energy Markets Tariff, the Agreement of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation,” or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and the Midwest ISO and any of their respective members or market participants.

2.2.27 “Intellectual Property”
Intellectual Property shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

2.2.28 “Interconnection Service”
Interconnection Service shall mean the service provided by the Transmission Service Provider associated with interconnecting the generating facility to the transmission system and enabling it to receive electric energy and capacity from the generating facility at the point of interconnection, pursuant to the terms of the generator interconnection agreement and, if applicable, the tariff.

2.2.29 “Interconnection Study”
Interconnection Study shall mean any of the following studies: the interconnection Feasibility Study, the interconnection System Impact Study, and the interconnection Facilities Study, or the restudy of any of the above, described in the generator interconnection procedures.

2.2.30 “Interconnection Reliability Operating Limit”
Interconnection Reliability Operating Limit shall mean a System Operating Limit that, if violated could lead to instability, uncontrolled separation(s) or cascading outages that adversely impact the reliability of the Bulk Electric System.

2.2.31 “Interregional Coordination Process”
Interregional Coordination Process shall mean the market-to-market coordination document incorporated herein as Attachment 3 to this Agreement, hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.32 “Inter-regional Planning Stakeholder Advisory Committee”
Inter-regional Planning Stakeholder Advisory Committee shall have the meaning given under Section 9.1.2.
2.2.33 “Inter-RTO Steering Committee”
Inter-RTO Steering Committee shall have the meaning given in the Joint and Common Market Agreement.

2.2.34 “Joint and Common Market”
Joint and Common Market shall mean, a group of initiatives that are intended to result in achievement of the following objectives: (i) Provide the highest level of inter-regional reliability; (ii) Deliver the lowest cost energy and ancillary services to load across the combined Midwest ISO and PJM Markets; and (iii) Plan, build and operate the combined Midwest ISO and PJM transmission facilities for maximum joint benefit across the markets.

2.2.35 “Joint and Common Market Agreement”
Joint and Common Market Agreement shall mean the Agreement Concerning Inter-regional Coordination, Including Development of Joint and Common Market, executed by the Parties on or about February 12, 2003.

2.2.36 “Joint Coordinated System Plan”
Joint Coordinated System Plan shall have the meaning given under Section 9.3.2.

2.2.37 “Local Balancing Authority”
Local Balancing Authority shall mean an operational entity which is: (i) responsible for compliance to NERC for the subset of NERC Balancing Authority Reliability Standards defined for its local area within the Midwest ISO Balancing Authority Area, and (ii) a party (other than the Midwest ISO) to the Balancing Authority Amended Agreement which, among other things, establishes the subset of NERC Balancing Authority Reliability Standards for which the LBA is responsible.

2.2.38 “Local Balancing Authority Area”
Local Balancing Authority Area shall mean the collection of generation, transmission, and loads that are within the metered boundaries of an LBA.

2.2.39 “Locational Marginal Price” or “LMP”
Locational Marginal Price or LMP shall mean the market clearing price for energy at a given location in a Party’s RC Area, and “Locational Marginal Pricing” shall mean the processes related to the determination of the LMP.

2.2.40 “LMP Contingency Processor”
LMP Contingency Processor shall mean that Locational Marginal Price pricing computer program referred to in Section 11.2.1.

2.2.41 “Market-Based Operating Entity”
Market-Based Operating Entity shall mean an Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.
2.2.42 **“Market Flows”**  
Market Flows shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity’s market (excluding tagged transactions).

2.2.43 **“Market Monitor”**  
Market Monitor shall monitor market power and other competitive conditions in the Markets and make reports and recommendations as appropriate.

2.2.44 **“Midwest ISO”**  
Midwest ISO has the meaning stated in the preamble of this Agreement.

2.2.45 **“NERC Compliance Registry”**  
NERC Compliance Registry shall mean a listing of all organizations subject to compliance with the approved reliability standards.

2.2.46 **“Network Upgrades”**  
Network Upgrades shall have the meaning as defined in the Midwest ISO and PJM tariffs.

2.2.47 **“Notice”**  
Notice shall have the meaning stated in Section 18.10.

2.2.48 **“Operating Entity”**  
Operating Entity shall mean an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.49 **“Outages”**  
Outages shall mean the planned unavailability of transmission and/or generation facilities dispatched by PJM or the Midwest ISO, as described in Article VII of this Agreement.

2.2.50 **“Party” or “Parties”**  
Party or Parties refers to each party to this Agreement or both, as applicable.

2.2.51 **“PJM”**  
PJM has the meaning stated in the preamble of this Agreement.

2.2.51a **“Project Cost”**  
Project Cost shall mean all costs for Network Upgrades, as determined by the RTOs to be a single transmission expansion project, including those costs associated with seeking and obtaining all necessary approvals for the design, engineering, construction, and testing the Network Upgrades. Project Cost will include costs classified by the Transmission Owners and ITCs as transmission plant using the Uniform System of Accounts or equivalent set of accounts for any Coordinating Owner, where Transmission Owners,
ITCs, and Coordinating Owner have the meanings as defined under the PJM and Midwest ISO OATTs.

2.2.52 “Purchasing-Selling Entity”
Purchasing Selling Entity shall mean the entity that purchases or sells, and takes title to, energy, capacity, and interconnected operations services.

2.2.53 “Reciprocal Coordination Agreement”
Reciprocal Coordination Agreement shall mean an agreement between Operating Entities to implement the reciprocal coordination procedures defined in the Congestion Management Process.

2.2.54 “Reciprocal Coordinated Flowgate”
Reciprocal Coordinated Flowgate shall mean a Flowgate that is subject to reciprocal coordination by Operating Entities, under either this Agreement (with respect to Parties only) or a Reciprocal Coordination Agreement between one or more Parties and one or more Third Party Operating Entities. An RCF is:

- A Coordinated Flowgate that is (a) (i) within the operational control of a Reciprocal Entity or (ii) may be subject to the supervision of a Reciprocal Entity as a RC, and (b) affected by the transmission of energy by the Parties or by either Party of both Parties and one or more Reciprocal Entities; or
- A Coordinated Flowgate that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to CMP reciprocal coordination procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or
- A Coordinated Flowgate that is designated by agreement of both Parties as a RCF.

2.2.55 “Reciprocal Entity”
Reciprocal Entity shall mean an entity that coordinates the future-looking management of Flowgate capability in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.55a “Regionally Beneficial Project”
Regionally Beneficial Project shall have the meaning defined under Attachment FF of the Midwest ISO OATT.

2.2.56 “Reliability Coordinator”
Reliability Coordinator shall mean that party approved by NERC to be responsible for reliability of an RC Area.

2.2.57 “Reliability Coordinator Area” or “RC Area”
Reliability Coordinator Area or RC Area shall mean the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

2.2.58 “SCADA Data”
SCADA Data shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC reliability standard TOP-005.

2.2.59 “State Estimator”
State Estimator shall mean that computer model that computes the state (voltage magnitudes and angles) of the transmission system using the network model and real-time measurements. Line flows, transformer flows, and injections at the buses are calculated from the known state and the transmission line parameters. The state estimator has the capability to detect and identify bad measurements.

2.2.60 “System Impact Study”
System Impact Study shall mean an engineering study that evaluates the impact of a proposed interconnection or transmission service request on the safety and reliability of transmission system and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the generating facility were interconnected or transmission service commenced without project modifications or system modifications.

2.2.61 “System Operating Limit”
System Operating Limit shall mean the value (such as MW, MVAR, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

2.2.62 “Third Party”
Third Party refers to any entity other than a Party to this Agreement.

2.2.63 “Third Party Operating Entity”
Third Party Operating Entity shall refer to a Third Party entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.64 “Total Flowgate Capability”
Total Flowgate Capability shall mean the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the Flowgate. The Flowgate capability is in units of megawatts. If the Flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions.

2.1.65 “Transmission Loading Relief”

Transmission Loading Relief shall mean the procedures used in the Eastern Interconnection as specified in NERC reliability standard IRO-006 and the NAESB business practice WEQ-008.

2.2.66 “Transmission Operator”
Transmission Operator shall mean the entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

2.2.67 “Transmission Owner”
Transmission Owner shall mean a Transmission Owner as defined under the Parties’ respective tariff.

2.2.68 “Transmission Reliability Margin”
Transmission Reliability Margin shall mean that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

2.2.69 “Transmission Service Provider”
Transmission Service Provider shall mean the entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

2.2.70 “Transmission System Emergencies”
Transmission System Emergencies are conditions that have the potential to exceed or would exceed an IROL.

2.2.71 “Unit Dispatch Systems”
Unit Dispatch Systems shall mean those dispatch systems utilized by the Parties to dispatch generation units by calculating the most economic solution while simultaneously ensuring that each of the boundary constraints is resolved reliably.

2.2.72 “Voltage and Reactive Power Coordination Procedures”
Voltage and Reactive Power Coordination Procedures are the procedures under Article XIX for coordination of voltage control and reactive power requirements.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
Section 2.3 Rules of Construction Version: 0.0.0 Effective: 9/17/2010

2.3 Rules of Construction.

2.3.1 No Interpretation Against Drafter.
In addition to their roles as RTOs and RCs, and the functions and responsibilities associated therewith, the Parties agree that each Party participated in the drafting of this Agreement and was represented therein by competent legal counsel. No rule of construction or interpretation against the drafter shall be applied to the construction or in the interpretation of this Agreement.

2.3.2 Incorporation of Preamble and Recitals.
The Preamble and Recitals of this Agreement are incorporated into the terms and conditions of this Agreement and made a part thereof.

2.3.3 Meanings of Certain Common Words.
The word “including” shall be understood to mean “including, but not limited to.” The word “Section” refers to the applicable section of this Agreement and, unless otherwise stated, includes all subsections thereof. The word “Article” refers to articles of this Agreement.

2.3.4 Certain Headings.
Certain sections of Articles IV, V, and VIII contain descriptions or statements of the purposes of, or requirements stated, in those sections. These descriptions or statements are to provide background information to assist in the interpretation of the requirements. The absence of a description or statement of purpose with respect to any requirement does not diminish the enforceability of the requirement. If a provision in Articles IV, V, and VIII is not delineated as “purpose,” “background,” or “definition,” it is a requirement.

2.3.5 NERC Reliability Standards.
All activities under this Agreement will meet or exceed the applicable NERC reliability standards as revised from time to time.

2.3.6 NAESB Business Practices.
All activities under this Agreement will meet or exceed the applicable NAESB business practices as revised from time to time.

2.3.7 Scope of Application.
Each Party will perform this Agreement in accordance with its terms and conditions with respect to each BA for which it serves as RTO and, in addition, each BA for which it serves as RC.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE III OVERVIEW OF COORDINATION AND INFORMATION EXCHANGE

Version: 0.0.0 Effective: 9/17/2010

ARTICLE III
OVERVIEW OF COORDINATION AND INFORMATION EXCHANGE

3.1 Ongoing Review and Revisions.
PJM and Midwest ISO will use this Joint Operating Agreement, to the extent applicable, for the coordination of TOP, BA, RC and other functions for which they may have registered in the NERC Compliance Registry. The Parties have agreed to the coordination and exchange of data and information under this Agreement to enhance system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and technology applicable to these systems and to the collection and exchange of data will change from time to time throughout the term of this Agreement, including changes to the boundaries of a Party in its capacity as an RTO, changes to the boundaries of, or identities of, BAs or TOPs for which a Party serves as RC, changes in response to findings and recommendations of the United States Department of Energy or NERC concerning the outage of August 14, 2003, and changes upon the commencement of market-to-market implementation. The Parties agree that the objectives of this Agreement can be fulfilled efficiently and economically only if the Parties, from time to time, review and as appropriate revise the requirements stated herein in response to such changes, including deleting, adding, or revising requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 4.1 Exchange of Operating Data Version: 0.0.0 Effective: 9/17/2010

4.1 Exchange of Operating Data.

Purpose: Sharing data is necessary to facilitate effective coordination of operations and to maintain regional system reliability while assuring the maximum commercial flexibility for market participants.

Requirements: The Parties will exchange the following types of data and information on a continuous, real-time basis:

(a) Real-Time and Projected Operating Data;
(b) SCADA Data;
(c) EMS Models;
(d) Operations Planning Data; and
(e) Planning Information and Models.

Each Party shall provide the data identified in items (a) through (e) of this Section to the other Party with respect to all entities that participate in Party’s markets during the term of this Agreement, whether or not the entity is a participant as of the Effective Date.

To facilitate the exchange of all such data, each Party will designate to the other Party’s Vice President of Operations a contact to be available twenty-four (24) hours each day, seven (7) days per week, and an alternate contact to act in the absence or unavailability of the primary contact, to respond to any inquiries. With respect to each contact and alternate, each Party shall provide the name, telephone number, e-mail address, and fax number. Each Party may change a designee from time to time by Notice to the other Party’s Vice President of Operations.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. If any required data exchange format has not been agreed upon as of the Effective Date, or if a Party determines that an agreed format should be revised, a Party shall give Notice of the need for an agreed format or revision and the Parties will jointly seek to complete development of the format within thirty (30) days of such Notice.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 4.1.1 Real-Time and Projected Operating Data Version: 0.0.0 Effective:

9/17/2010

4.1.1 Real-Time and Projected Operating Data.

4.1.1.1 Requirements:
The Parties will exchange two categories of operating data (real-time information and projected information), as follows:

(a) The real-time operating information consists of:
   (i) Generation status of the units in each Party’s RC Area;
   (ii) Transmission line status;
   (iii) Real-time loads;
   (iv) Scheduled use of reservations;
   (v) TLR information, including calculation of Market Flows;
   (vi) Redispatch information, including the next most economical generation block to decrement/increment; and
   (vii) List of real-time constraints that are binding in the real-time market solution.

(b) Projected operating information consists of:
   (i) Merit order for generators participating in the Parties’ markets;
   (ii) Maintenance schedules for generators and transmission facilities in either of the Parties’ RC Area;
   (iii) Transmission Service Reservations reflecting firm purchase and sales;
   (iv) Independent power producer information including current operating level, projected operating levels, Outage start and end dates;
   (v) The planned and actual operational start-up dates for any permanently added, removed or significantly altered transmission segments; and
   (vi) The planned and actual start-up testing and operational start-up dates for any permanently added, removed or significantly altered generation units.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 4.1.2 Exchange of SCADA Data Version: 0.0.0 Effective: 9/17/2010

4.1.2 Exchange of SCADA Data.

Background: NERC reliability standard TOP-005 Attachment 1 “Electric System Reliability Data,” describes the types of data that TOPs, BAs, and Purchase Selling Entities are expected to provide, and RCs are expected to share with each other as explained in reliability standard TOP-005 “Operational Reliability Information.”

Requirements:

(a) The Parties shall exchange requested transmission power flows, measured bus voltages and breaker equipment statuses of their bulk transmission facilities via ICCP or ISN.

(b) Each Party shall accommodate, as soon as practical, the other Party’s requests for additional existing ICCP/ISN bulk transmission data points, but in any event no more than one (1) week after the request has been submitted.

(c) Each Party shall respond, as soon as practical, to the other Party’s requests for additional, unavailable ICCP/ISN bulk transmission data points, but in any event no more than two (2) weeks after the request has been submitted, with an expected availability target date for the requested data.

(d) The Parties will comply with all governing confidentiality agreements executed by the Parties relating to ICCP/ISN data.

(e) The Parties shall exchange SCADA Data consisting of:

(i) Status measurements 69 kV and above (breaker statuses) (as available and required to observe for reliability as the respective Parties may determine);

(ii) Analog measurements 69 kV and above (flows and voltages); (as available and required to observe for reliability as the respective Parties may determine);

(iii) Generation point measurements, including generator output for each unit in MW and MVARS, as available;

(iv) Load point measurements, including bus loads and specific loads at each substation in MW and MVARS, as available;

(v) BAA net interchange;

(vi) BAA instantaneous demand;

(vii) BAA operating reserves; and

(viii) Identification of other real-time data available through ICCP/ISN.
4.1.3 Models

**Purpose:** EMS models contain detailed representations of the transmission and generation configurations within each RTO and neighboring systems. The Parties depend upon EMS models for reliability coordination and market operations. The regular exchange of models is to ensure that each Party is using current and up-to-date representations of the other Party.

**Requirements:** The Parties will exchange their detailed EMS models once a year in CIM format or another mutually agreed upon electronic format, but shall provide each other with updates of the model information in an agreed upon electronic format as new data becomes available. This yearly exchange will include the ICCP/ISN mapping files, identification of individual bus loads, seasonal equipment ratings and one-line drawing that will be used to expedite the model conversion process. The Parties will also exchange updates that represent the incremental changes that have occurred to the EMS model since the most recent update.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
4.1.4 Operations Planning Data

Purpose: Operations planning data, which defines how a system was planned and built, is basic information needed to coordinate planning and operations between the Parties.

Requirements: Upon the written request of a Party, the other Party shall provide the information specified in Sections 4.1.4.1 through 4.1.4.11 inclusive, or any components thereof. Each request shall specify the information sought and the requested frequency upon which it would be provided. A Party receiving a request under this Section shall provide the information promptly to the extent the information is available to the Party. Operations planning data is not generally considered Confidential Information but to the extent any of this data overlaps previously defined operating data in Section 4.1.2, it is considered Confidential Information.

4.1.4.1 Flowgates.

(a) Flowgate definitions including seasonal TFC, TRM, CBM, and a & b multipliers;
(b) Flowgates to be added on demand;
(c) List of Coordinated and Reciprocal Coordinated Flowgates;
(d) List of Flowgates to recognize when selling point-to-point service (if different than list of Coordinated Flowgates); and
(e) Requirements under Section 5.1.7.

4.1.4.2 Transmission Service Reservations.

(a) Daily list of all reservations, hourly increment of new reservations;
(b) List of reservations to exclude;
(c) Requirements under Sections 5.1.4 and 5.1.5; and
(d) List of long-term firm reservations not subject to rollover rights.

4.1.4.3 Available Flowgate Capability Data.
Each Party will meet a minimum periodicity for calculating and making available AFCs to each other. The minimum periodicity depends on the service being offered. Each Party will provide the following AFC data to the other Party:

(a) Hourly for first seven (7) days posted at a minimum, once per hour;
(b) Daily for days eight (8) through thirty-one (31), posted at a minimum, once per day; and
(c) Monthly for months two (2) through eighteen (18), posted at a minimum, twice per month.

4.1.4.4 Load Forecast.

(a) Hourly for next seven (7) days, daily for days eight (8) through thirty-one (31), and monthly for months two (2) through eighteen (18), submitted once a day;
(b) Identify the origin of the forecast (e.g., identity of RTO, RC, BA, etc.);
(c) Indicate whether this forecast includes transmission system losses, and if it does, indicate what the percent losses are;
(d) Identify non-conforming loads;
(e) Indicate how municipal entities, cooperatives and other entity loads are treated. Indicate whether they are included in the forecast. If so, indicate the total load or net load after removing other entity generation; and
(f) Requirements under Section 5.1.6.

4.1.4.5 Generator Data.

(a) Unit owner, bus location in model;
(b) Seasonal ratings, PMIN, PMAX, QMIN, QMAX;
(c) Station auxiliaries to extent gross generation has been reported; and
(d) Regulated bus, target voltage and actual voltage.

4.1.4.6 Designated Network Resources.
(a) Network Integration Transmission Service Specifications;

(b) Designated Network Resource information; and

(c) To the extent that Designated Network Resources operate between the markets administered by the Parties:
   (i) Indication of treatment as pseudo tie or dynamic/static schedules;
   (ii) Rules for sharing output between joint owners; and
   (iii) Transmission arrangements.

4.1.4.7 BAA Net Interchange from Reservations and Tags.

(a) Any grandfathered agreements that do not appear in OASIS; and

(b) If tags and reservations cannot be used to develop BAA net interchange, then provide hourly unit commitment information for all generators in the BAA.

4.1.4.8 Dynamic Schedules.

(a) List of dynamic schedules;

(b) Identification of the dynamic schedules are being used to move load between the Parties’ respective RC Areas;

(c) Identification of marginal generation zones; and

(d) Requirements under Section 5.1.11.

4.1.4.9 Controllable Devices.

(a) Phase shifters;

(b) Market-dispatchable demand response resources greater than 50 MW.

(c) DC lines; and

(c) Back-to-back AC/DC converters.

4.1.4.10 Generation and Transmission Outages.
(a) Generation Outages that are planned or forecast, as soon as practicable, including all data specified in Section 5.1.1;

(b) Transmission Outages that are planned or forecast, as soon as practicable, including all data specified in Section 5.1.3; and

(c) Notification of all forced outages of both generation and transmission resources, not to exceed 30 minutes after they are identified.

4.1.4.11 Exchange of Operating Data.

The Parties shall exchange such information as the Market Monitors of PJM and Midwest ISO may request, singly or jointly, in order to facilitate monitoring of markets in accordance with the Parties’ respective FERC-approved market monitoring plans.

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Section 4.2 Access to Data to Verify Market Flow Calculations Version: 0.0.0

Effective: 6/16/2011

4.2 Access to Data to Verify Market Flow Calculations.

Each Party shall provide the other Party with data to enable the other Party independently to verify the results of the calculations that determine the market-to-market settlements under this Agreement. A Party supplying data shall retain that data for two years from the date of the settlement invoice to which the data relates, unless there is a legal or regulatory requirement for a longer retention period. The method of exchange and the type of information to be exchanged pursuant to this Section 4.2 shall be specified in writing and posted on the Parties’ websites. The posted methodology shall provide that the Parties will cooperate to review the data and mutually identify or resolve errors and anomalies in the calculations that determine the market-to-market settlements. If one Party determines that it is required to self report a potential violation to the Commission’s Office of Enforcement regarding its compliance with this Agreement, the reporting Party shall inform, and provide a copy of the self report to, the other Party. Any such report provided by one Party to the other shall be “confidential information” as defined in this Agreement.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
4.3 Cost of Data and Information Exchange.

Requirements: Each Party shall bear its own cost of providing information to the other Party pursuant to Section 4.1, except to the extent this provision is contrary to (a) any solution the FERC places into effect to the “hold harmless” issues the FERC identified in Alliance Companies, 100 FERC ¶ 61,137 (July 31, 2002); on rehearing, 103 FERC ¶ 61,274 (June 4, 2003), and related clarifying orders, the “Hold Harmless Issues,” or (b) any agreement or agreements which include the following entities: Michigan and Wisconsin parties (as described in the FERC Order referenced above), Commonwealth Edison, and American Electric Power which the FERC accepts as a solution to the Hold Harmless Issues.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
ARTICLE V AFC CALCULATIONS Version: 0.0.0 Effective: 9/17/2010

ARTICLE V
AFC CALCULATIONS

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
5.1 AFC Protocols.

**Purpose:** The calculation of AFC is a forecast of transmission capability that may be available for use by transmission customers. Use of transmission capability in one system can impact the loadings, voltages and stability of neighboring systems. Because of this interrelationship, neighboring entities must exchange pertinent data for each entity to determine the AFC values for its own transmission system. The exchange of data related to calculation of AFC is necessary to assure reliable coordination, and also to permit either Party to determine if, due to lack of transmission capability, it must refuse a transmission reservation in order to avoid potential overloading of facilities.

As of the date of this Agreement, the Parties use the SDX System to exchange the planned status of generators rated greater than 50 MW, outages of all interconnections and other transmission facilities operated at greater than 100 kV, and peak load forecasts. This system has the capability to house hourly data for the next seven (7) days, daily data for the next thirty one (31) days, weekly data for the next month, and monthly data for the next three years. Continued use of this tool, and associated commitments under this Agreement, will assure the Parties’ ability to make reliable calculations efficiently.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
5.1.1 Generation Outage Schedules.

Requirements: Each Party shall provide the other with projected status of generation availability over the next twelve (12) months or more if available. The Parties will update this data no less than once daily for the full posting horizon and more often as required by system conditions. The data will include complete generation maintenance schedules and the most current available generator availability data, such that each Party is aware of each “return date” of a generator from a scheduled or forced outage. At all times, this exchange will include the status of generators rated greater than 50 MW. If the status of a particular generator of equal to or less than 50 MW is used within a Party’s AFC calculation, the status of this unit shall also be supplied.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
**Section 5.1.2 Generation Dispatch Order Version: 0.0.0 Effective: 9/17/2010**

5.1.2 Generation Dispatch Order.

**Purpose:** Dispatch information combined with unit availability information permits each Party to develop a reasonably accurate dispatch for any modeled condition. This methodology is more advantageous than scaling all available generation to meet generation commitments within an area and then increasing all generation uniformly to model an export, or uniformly decreasing all generation to model an import. While excluding nuclear generation or hydro units from this scaling would provide some level of refinement, this approach is inadequate to identify transmission constraints and determine rational AFC values.

The exchange of typical generation dispatch order or generation participation factors of all units on a BAA basis and other data under this Agreement will permit each Party to appropriately model future transmission system conditions.

**Requirements:** As necessary to permit a Party to develop a reasonably accurate dispatch for any modeled condition, each Party will provide the other Party with a typical generation dispatch order or the generation participation factors of all units on an affected BAA basis. The generation dispatch order will be updated as required by changes in the status of the unit; however, a new generation dispatch order need not be provided more often than prior to each peak load season.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
5.1.3 Transmission Outage Schedules

Requirements: Each Party will provide the other Party with the projected status of transmission outage schedules above 100 kV over the next twelve (12) months or more if available. This data shall be updated no less than once daily for the full posting horizon and more often as required by system conditions. The data will include current, accurate and complete transmission facility maintenance schedules, including the “outage date” and “return date” of a transmission facility from a scheduled or forced outage.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 5.1.4 Transmission Interchange Schedules/Net Scheduled Interchange Version:

0.0.0 Effective: 9/17/2010

5.1.4 Transmission Interchange Schedules/Net Scheduled Interchange.

**Purpose:** Because interchange schedules impact the short-term use of the transmission system, exchange of schedule data is necessary to determine the remaining capacity of the transmission system as well as to determine the net impact of loop flow.

**Requirements:** Each Party will make available to the other its reservation and interchange schedules/NSI, as required to permit accurate calculation of AFC values. Due to the high volume of this data, the Parties shall either post this data to a mutually agreed upon site for downloading or utilize tag dump information by the other Party as required by its own process and timing requirements.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 5.1.5 Reservations Version: 0.0.0 Effective: 9/17/2010

5.1.5 Reservations.

Purpose: Beyond the operating horizon, the impacts of existing transmission reservations are also necessary for the calculation of AFC for future time periods. Inasmuch as a transmission reservation is a right to use and not an obligation to use the transmission system, there is no certainty that any particular reservation will result in a corresponding interchange schedule. This is especially true considering that the pro forma OATT approved by the FERC allows firm service on a given path to be redirected as non-firm service on any other path. In addition, the ultimate transmission customer may not have, at a given time, purchased all transmission reservations on a particular source-to-sink path. A further complication is that the duration or firmness of the one portion of the reservation may not be the same as the remaining portion. Since prior to scheduling, it is difficult to associate reservations involving multiple Transmission Providers that may be used to complete a single transaction, double counting in the AFC determination process is a possibility. It is acknowledged that reservations respecting one Party are not required to be incorporated into transmission models developed by the other Party.

Requirements:

(a) Each Party will make available to the other Party, upon a mutually agreed upon site, actual transmission service requests information for integration into each Party’s AFC determination process.

(b) Each Party will develop practices for modeling transmission service requests, including external requests, and netting practices for any allowance of counterflows created by reservations in electrically opposite directions. Each Party will provide the other Party with the procedures developed and implemented to model intra-party requests, requests on external parties, and reservation netting.

(c) Each Party shall also create, maintain, and exchange a list of reservations from its OASIS that should not be considered in AFC calculations. Reasons for these exceptions include, for example, grandfathered agreements that grant access to more transmission than is necessary for the related generation capacity and unmatched intra-Party partial path reservations. If a Party does not include a reservation in its own evaluation, the reservation should be excluded in the other Party’s analysis.

(d) Each Party shall maintain a list of long-term firm reservations that are not subject to rollover rights and accordingly treat them in their process.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 5.1.6 Load Data Version: 0.0.0 Effective: 9/17/2010

5.1.6 Load Data.

Requirements: The Parties will exchange forecasted peak load data for each period in accordance with NERC reliability standards and NAESB business practices (e.g., daily, weekly, and monthly). Since, by definition, peak load values may only apply to one (1) hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. This is in accordance with the FERC’s regulations at 18 C.F.R¹ § 37.6(b)(4)(iv). For the next seven (7) day horizon, the Parties shall either supply hourly load forecasts or they shall supply daily peak load forecasts with a load profile. All load forecasts will be provided on a BAA or zone basis by the applicable RTO, RC, BA, or other applicable entity, including total distribution forecast by zones.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000

¹The Code of Federal Regulations (CFR) is the codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the Federal Government.
Section 5.1.7 Calculated Firm and Non-firm AFC Version: 0.0.0 Effective: 9/17/2010

5.1.7 Calculated Firm and Non-firm AFC.

**Purpose:** Data exchange is required to determine if a transmission service reservation (or interchange schedule) will impact Flowgates to an extent greater than the (firm or non-firm) AFC and procedures are necessary to assure that each Party respects the other Party’s Flowgates as follows.

**Requirements:**

(a) The Parties will exchange firm and non-firm AFC for all relevant Flowgates.

(b) Each Party will accept or reject transmission service requests based upon projected loadings on its own Flowgates as well as on RCFs under Article VI.

(c) Each Party will limit approvals of requests for transmission service between the Parties, including roll-over transmission service, so as to not exceed the lesser of the sum of the thermal or stability capabilities of the tie lines that interconnect the Parties, provided that firm transmission service customers retain the rollover rights and reservation priority granted to them under the applicable Party’s OATT, and further provided that if explicitly stated in the applicable service agreement, a Party may limit rollover rights for new long-term firm service if there is not enough AFC to accommodate rollover rights beyond the initial term.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 5.1.8 Total Flowgate Capability (Flowgate Rating) Version: 0.0.0 Effective: 9/17/2010

5.1.8 Total Flowgate Capability (Flowgate Rating).

Requirements: The Parties will exchange (seasonal, normal and emergency) Total Flowgate Capability as well as all limiting conditions (thermal, voltage, or stability). The Parties will update this information in a timely manner as required by changes on the transmission system.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
5.1.9 Identification of Flowgates.

Requirements: Each Party shall consider in its TFC and AFC determination process all Flowgates: (i) that may initiate a TLR event, (ii) that are significantly impacted by their own Party’s transactions, or (iii) as mutually agreed between the Parties. A Party’s transactions are deemed to significantly impact another Party’s Flowgates if they have a response factor equal to or greater than the response factor cut-off used by the owning Party. The Parties in their AFC determination and transmission service processing efforts shall use the response factor cut-off that the owning/operating Party uses for its Flowgates.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
5.1.10 Configuration/Facility Changes (for power system model updates).

Requirements:

(a) A mechanism will be maintained between the Parties to ensure that all significant system changes of a neighbor are incorporated in each Party’s AFC calculation model. Although this information and a host of very detailed data are included in the MMWG/ERAG cases, this data exchange mechanism will address the ‘major’ changes that should be included in the AFC calculation models in a more timely manner. This data exchange will occur no less often than prior to each peak load season.

(b) In addition, the Parties agree to exchange AFC calculation models of their transmission systems as soon as mechanisms can be established to facilitate this exchange.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 5.1.11 Dynamic Schedule Flows Version: 0.0.0 Effective: 9/17/2010

5.1.11 Dynamic Schedule Flows.

Requirements: Each Party agrees to provide the other Party with the actual amount and future projection of dynamic schedule flows. All dynamic schedule flows and tags will be submitted in accordance with NERC policy and procedures.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 5.1.12 Coordination of Transmission Reliability Margin Values Version: 0.0.0

Effective: 9/17/2010

5.1.12 Coordination of Transmission Reliability Margin Values.

Requirements: Each Party shall make transmission capability available for reserve sharing by including the significant impacts of the other Party’s generation outages in its TRM values. The Parties will coordinate and share the necessary information for the determination of these impacts as necessary.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE VI RECIPROCAL COORDINATION OF FLOWGATES

Effective: 9/17/2010

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 6.1 Reciprocal Coordination of Flowgates Operating Protocols Version:

0.0.0 Effective: 9/17/2010

6.1 Reciprocal Coordination of Flowgates Operating Protocols.

6.1.1 Reciprocal Coordinated Flowgates.
In order to coordinate congestion management proactively, each Party agrees to respect the other Party’s determinations of AFC and calculations of firmness (firm, non-firm, network, non-firm hourly) for real-time operations applicable to the Party’s Coordinated Flowgates. Additionally, each Party agrees to respect the allocations defined by the allocation process set forth in Section 6 of the Congestion Management Process.

6.1.2 Coordination Process for Reciprocal Coordinated Flowgates.
The Parties shall maintain the process and timing for exchanging their respective AFC calculations and Firm Flow calculations/allocation with respect to all RCFs. Further, the process will allocate Flowgate capability on a future-looking basis, including the allocation of Firm Capability for use in both internal dispatch and selling of transmission service. The Congestion Management Process sets forth the procedure for reciprocal coordination. For any controllable Flowgate, the historically determined Firm Flow on the Flowgate and any allocated rights to that Flowgate under this process are subject to the operating practices of the controllable device. The operating practices of the controllable device will be made available to the Midwest ISO and PJM before a change is made. To the extent the controllable device is able to maintain the schedule across the controllable Flowgate, there are no parallel flows and a historical allocation based on parallel flows will not occur. In this instance, the use of the controllable Flowgate will be limited to entities that have arranged transmission service across the interface formed by the controllable device. To the extent the controllable device cannot maintain the schedule across the controllable Flowgate, there will be a historical allocation based on parallel flows.

The Parties’ capabilities and real-time actions shall be governed by and in accordance with the Congestion Management Process.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 6.2 Costs Arising From Reciprocal Coordination of Flowgates Version:

0.0.0 Effective: 9/17/2010

6.2 Costs Arising From Reciprocal Coordination of Flowgates.
In the event redispatch occurs in order to coordinate congestion management under
Section 6.1 or subparts thereof, including redispatch necessary to respect the other Party’s
Flowgate, as set forth in Article XI, the Party responsible for the flow that required the
redispatch shall bear the costs of the redispatch.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 6.3 Transmission Capability for Reserve Sharing Version: 0.0.0 Effective:

9/17/2010

6.3 Transmission Capability for Reserve Sharing.
Each Party shall make transmission capability available for reserve sharing by either
redispatching its Flowgates or holding TRM for generation outages in the other Party’s
system. The Party responsible for making transmission capability available for the
reserve sharing obligation shall bear the costs of the redispatch to the extent the costs
may be recovered under such Party’s OATT.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 6.4 Maintaining Current Flowgate Models Version: 0.0.0 Effective: 9/17/2010

6.4 Maintaining Current Flowgate Models.
Each Party will maintain a detailed model of the other Party’s system for operations and planning purposes. Each Party’s model will be sufficiently detailed to properly honor all of that Party’s Coordinated Flowgates. Furthermore, each Party will populate its model with credible data and will keep such models up-to-date.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
6.5 Sharing Contract Path Capacity.

If the Parties have contract paths to the same entity, the combined contract path capacity will be made available for use by both Parties. This will not create new contract paths for either Party that did not previously exist. PJM will not be able to deal directly with companies with which it does not physically or contractually interconnect and the Midwest ISO will not be able to deal directly with companies with which it does not physically or contractually interconnect.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE VII COORDINATION OF OUTAGES Version: 0.0.0 Effective: 9/17/2010

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 7.1 Coordinating Outages Operating Protocols Version: 0.0.0 Effective:

9/17/2010

7.1 Coordinating Outages Operating Protocols.
The Parties have an interregional outage coordination process for coordinating transmission and generation Outages to ensure reliability. The Parties agree to the following with respect to transmission and generation Outage coordination.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 7.1.1 Exchange of Transmission and Generation Outage Schedule Data

Version: 0.0.0 Effective: 9/17/2010

7.1.1 Exchange of Transmission and Generation Outage Schedule Data.

Upon a Party’s request, the projected status of generation and transmission availability will be communicated between the Parties, subject to data confidentiality agreements. All available information regardless of scheduled date will be shared. The Parties shall exchange the most current information on proposed Outage information and provide a timely response on potential impacts of proposed Outages.

The Parties agree that this information will be shared promptly upon its availability, but no less than daily and more often as required by system conditions. The Parties shall utilize a common format for the exchange of this information. The information includes the owning Party’s facility name; proposed Outage start date and time; proposed facility return date and time; date and time when a response is needed from the impacted Party to modify the proposed schedule; and any other information that may be relevant to the reliability assessment.

Each Party will also provide information independently on approved and anticipated Outages formatted as required for the SDX System.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
7.1.2 Evaluation and Coordination of Transmission and Generation Outages.

The Parties will utilize network applications to analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each Party’s Outage analysis will consider the impact of its critical Outages on the other Party’s system reliability, in addition to its own. The analysis will include, as a minimum, an evaluation of contingencies, including potential real or reactive power concerns, voltage analysis and real and reactive power reserve analysis.

On a weekly basis, daily if requested by one of the Parties, the operations staff of each Party shall jointly discuss any Outages to identify potential impacts. These discussions should include an indication of either concurrence with the Outage or identify significant impact due to the Outage as scheduled. Neither Party has the authority to cancel the other Party’s Outage (except transmission facilities interconnecting the two Parties’ transmission systems). However, the Parties will work together to resolve any identified Outage conflicts. Consideration will be given to Outage submittal times and Outage criticality when addressing Outage conflicts. If Outage analysis indicates unacceptable system conditions, the Parties will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of proposed maintenance. If an operating procedure cannot be developed and a change to the proposed schedule is necessary based on significant impact, the Parties shall discuss the facts involved and make every effort to effect the requested schedule change. If this change cannot be accommodated, the Party with the Outage shall notify the impacted Party. A request to adjust a proposed Outage date must include, identification of the facility(s) overloaded, and identify a similar time frame of more appropriate dates/times for the Outage.

The Parties will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known (not to exceed thirty (30) minutes). The Parties will evaluate the impact of emergency and forced outages on the Parties’ systems and work with one another to develop remedial steps as necessary.

Outage schedule changes, both before or after the work has started, may require additional review. Each Party will consider the impact of these changes on the other Party’s system reliability, in addition to its own. The Parties will contact each other as soon as possible if these changes result in unacceptable system conditions and will work with one another to develop remedial steps as necessary.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE VIII PRINCIPLES CONCERNING JOINT OPERATIONS IN EMERGENCIES

Version: 0.0.0 Effective: 9/17/2010

ARTICLE VIII
PRINCIPLES CONCERNING JOINT OPERATIONS IN EMERGENCIES

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 8.1 Emergency Operating Principles Version: 0.0.0 Effective: 9/17/2010

8.1 Emergency Operating Principles.

Purpose: Joint emergency principles are essential due to the highly dependent nature of facilities under different authorities. The Parties are committed to reliable operation of the transmission system under normal conditions, and will work closely together during emergency situations that place the stability of the transmission system in jeopardy.

Requirements:

8.1.1 In the event an emergency condition is declared in accordance with a Party’s published operating protocols, the Parties agree to provide emergency assistance to each other and to facilitate obtaining emergency assistance from a third party. The Parties will coordinate respective actions to provide immediate relief until the declaring Party eliminates the declaration of emergency. The Parties will notify each other of emergency maintenance and forced outages that would have a significant impact on the other Party as soon as possible after the conditions are known. The Parties will evaluate the impact of emergency and forced outages on the Parties’ systems and coordinate to develop remedial steps as necessary or appropriate. If the emergency response allows for coordinating with the other Party before action must be taken, the normal RTO to RTO request for action will be followed. The Parties will conduct joint annual emergency drills and will ensure that all operating staff are trained and certified, if required, and will practice the joint emergency drills that include criteria for declaring an emergency, prioritized action plans, staffing and responsibilities, and communications.

8.1.2 In furtherance of maintaining system stability and providing prompt response to problems, the Parties agree that in situations where there is an actual IROL violation and/or the system is on the verge of imminent collapse, and when there exists an applicable emergency principles or operating guide, each Party will allow the affected Party to take immediate steps by modifying the normal RTO to RTO request procedure so that both Parties and affected operating entities can communicate and coordinate simultaneously via telephone conference call or other appropriate means. Subsequent to such anomalous operations, the requesting Party will prepare a lessons learned report and provide copies thereof to the other Party and affected operating entities. The purpose of the lesson learned report is to assist in improving operations so that future operations will be more proactive; thereby, avoiding such abnormal communications/procedures.

8.1.3 The Parties will work together and with the BAs with respect to which they serve as RTO or RC to jointly develop and commit to additional emergency principles and operating guides as the need for such procedures arises. Existing emergency principles and operating guides shall be reviewed annually. The Parties will make readily available to local operating entities, including BA operators, the current RTO restoration plans.
including the information contained therein concerning the black start plans of interconnecting entities, subject to the procedures set forth in the then current business practices of the Parties, including appropriate security and confidentiality requirements.

8.1.4
Transmission System Emergencies may be implemented when, in the judgment of either Party, the system is in an emergency condition that is characterized by the potential, either imminently or for the next contingency, for system instability or cascading, or for equipment loading or voltages significantly beyond applicable operating limits, such that stability of the system cannot be assured, or to prevent a condition or situation that in the judgment of a Party is imminently likely to endanger life or property. In the event that either it becomes necessary for either Party to declare a Transmission System Emergency for an area that is in close electrical proximity to both of the Parties’ RC Areas, both Parties will declare a Transmission System Emergency or redispatch without declaring a Transmission System Emergency, and take action(s) in kind to address the situation that prompted the Transmission System Emergency consistent with safe operating mode. These actions may include:

(a) Curtailment of equivalent amounts of firm point-to-point transactions within both Parties;

(b) Redispachting of generation within both Parties; and

(c) Load shedding within both Parties.

8.1.5
In situations where an actual IROL violation exists, or for the next contingency would exist, and the transmission system is currently, or for the next contingency would be, on the verge of imminent collapse, and there is not an existing emergency principle or operating guide, each Party will receive, and subject to the next two sentences of this Section implement, the instruction of the affected Party, communicate the instruction to the affected entity within its own boundary, or utilize telephone conference call capabilities or other appropriate means of communication to allow simultaneous coordination/communication between the Parties and the affected entity. All occurrences of this kind may be reviewed by either or both Parties after the fact, but the instruction of the affected Party shall be implemented when issued, except a Party may delay implementation in instances where a Party concludes that the requested action will result in a more serious condition on the transmission system, or the requested action is imminently likely to endanger life or property. Financial considerations shall have no bearing on actions taken to prevent the collapse of the transmission system.

8.1.6
In a situation where an SOL violation exists within either Party’s RC Area, or for the next contingency would exist, the Parties will work together as necessary, following good utility practices, and take action in kind as required to address the situation.

8.1.7
In its capacity as RC with respect to certain BAs (as applicable), each Party has the responsibility and authority to coordinate with the other Party and, as may be provided under arrangements other than this Agreement, direct emergency action on the part of generation or transmission to protect the reliability of the network. Each Party shall exercise such authority in accord with good utility practice as required to resolve emergency conditions in the other Party’s RC Area of which it is aware and, in conjunction with its stakeholder processes, will develop detailed emergency operating procedures.

8.1.7.1 Power System Restoration.
Effective procedures for restoration of the network require coordination and communication at all levels of the Parties’ organizations and with their membership. During power system restoration, the Parties will coordinate their actions with each other, as well as with other RTOs and operating entities in order to restore the transmission system as safely and efficiently as possible. In order to enhance the effectiveness of actual restoration operations between the Parties, the Parties will conduct annual coordinated restoration drills. These drills will stress cooperation and communication so that both Parties are positioned to better assist each other in an actual restoration.

8.1.7.2 Joint Voltage Stability Operating Protocol.
Voltage stability or collapse problems have the potential to cause cascading outages and therefore must be closely coordinated to maintain reliable operations. The Parties will coordinate their operations in accordance with good utility practice in order to maintain stable voltage profiles throughout their respective RC Areas. The Parties will coordinate their established daily voltage/reactive management plans. This coordination will serve to assure an adequate static and dynamic reactive supply under a credible range of system dispatch patterns across both Parties’ systems and will assure the plans are complementary.

8.1.7.3 Operating the Most Conservative Result.
When any one Party identifies an overload/emergency situation that may impact the other Party’s system and the other Party’s results/systems do not observe a similar situation, both Parties will operate to the most conservative result until the Parties can identify the reasons for these differences(s).

8.1.8 Emergency Plans.
Each Party agrees to annually review and update its emergency energy plans. Each Party agrees to provide copies of its emergency energy plans to the other Party when the emergency plans are updated. Each Party agrees to coordinate their emergency energy plans with the other Party. The Parties recognize that part of this coordination is already established in this agreement as identified below.

8.1.8.1 Emergency Plan Coordination.
Each Party is responsible for overall Emergency Operations planning and coordination of such plans within its own BA. Each Party will include its affected member systems within its respective area into the development process of the
overall normal and emergency operating procedures. Each Party agrees to coordinate its load shedding plans with the other Party and other adjacent NERC TOPs and BAs.

8.1.9 Emergency Capacity or Energy.
A Party may request emergency assistance on the terms set forth in the Emergency Energy Transactions document. Each Party agrees to notify the other Party whenever it is currently experiencing or is projected to experience an energy or capacity emergency. Parties shall establish procedures for requesting and supplying emergency energy.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE IX COORDINATED REGIONAL TRANSMISSION EXPANSION PLANNING

Version: 0.0.0 Effective: 9/17/2010

ARTICLE IX
COORDINATED REGIONAL TRANSMISSION EXPANSION PLANNING

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 9.1 Administration; Committees Version: 0.0.0 Effective: 9/17/2010

9.1 Administration; Committees.

9.1.1 Joint RTO Planning Committee.

The ISC shall form, as a subcommittee, a JRPC, comprised of representatives of the Parties’ respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, every other year, to designate a Chairman of the JRPC to serve a one-year calendar term, except that the term of the first Chairman shall commence on the Effective Date and end December 31, 2004. The ISC shall designate the first Chairman. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings. The JRPC shall coordinate the coordinated system planning under this Agreement, including the following:

(a) Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed, the JRPC shall develop common power system analysis models to perform coordinated system planning, as well as models for power flow analyses, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the parties, the JRPC will direct the performance of a detailed review of the appropriateness of applicable power system models.

(b) Prepare, on a regular basis, a Coordinated System Plan as required under Section 9.3.5.

(c) Coordinate all planning activities under this Article IX, including the exchange of data under this Article.

(d) Maintain an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process.

(e) Meet at least semi-annually to review and coordinate transmission planning activities. Such meetings shall include, as determined by either party to be necessary based on internal discussions, discussion of any system operations or market operations issues as they impact long range planning and the coordination of planning between the systems.

(f) Support the review by any federal or provincial agency of elements of the Coordinated System Plan.

(g) Support the review by multi-state entities to facilitate the addition of inter-state transmission facilities.
(h) Establish working groups as necessary to provide adequate review and development of the regional plans.

(i) Establish a schedule for the rotation of responsibility for data management, coordination of stakeholder meetings, coordination of analysis activities, report preparation, and other activities.

(j) The JRPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under joint agreements to which the Parties are signatories, for the purpose of providing for broader and more effective inter-regional planning coordination.

9.1.2 Inter-regional Planning Stakeholder Advisory Committee.
The Parties shall form an IPSAC. The IPSAC shall facilitate stakeholder review and input into coordinated system planning with respect to the development of the Coordinated System Plan. IPSAC members shall consist of the stakeholder participants in joint stakeholder meetings called by the JRPC for the purpose of addressing issues under the responsibility of the JRPC as established by this Article IX. The IPSAC will meet no less frequently than prior to the start of each cycle of the coordinated planning process, during the development of the Coordinated System Plan, and upon completion of the plan to review final results.

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9.2 Data and Information Exchange.

In support of coordinated system planning, each Party shall provide the other with the following data and information. Unless otherwise indicated, such data and information shall be provided as requested by either party and as available, on a mutually agreed to schedule but no longer than 60 days from the date of such request.

(a) Data required for the development of load flow cases, short-circuit cases, and stability cases, including ten year load forecasts and all critical assumptions that are used in the development of these cases.

(b) Fully detailed planning models (up to the next ten (10) years), as requested by either party and on a mutually agreed schedule as a part of the development of any joint planning studies provided for under this Article IX or as otherwise agreed to.

(c) The regional plan document produced by the Party, any long-term or short-term reliability assessment documents produced by the Party, and any operating assessment reports produced by the Party.

(d) The status of expansion studies, system impact studies and generation interconnection studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies.

(e) Transmission system maps for the Party’s bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two systems.

(f) Contingency lists for use in load flow and stability analyses, including lists of all single contingency events and multiple facility tower line contingencies, as well as breaker diagrams for the portions of the Party’s transmission system that are relevant to the coordination of planning between the two systems.

(g) The timing of each planned enhancement, including estimated completion dates and project mobilization schedules, and indications of the likelihood a system enhancement will be completed and whether the system enhancement should be included in system expansion studies, system impact studies and generation interconnection studies, and all related applications for regulatory approval and the status thereof.

(h) Identification of and status of interconnection requests that have been received and any long-term firm transmission services that have been approved that may impact the operation of a Party’s system in a manner that affects the other Party’s system, shared on the earlier of the identification of the potential impact, within
30 days of such request by the other Party or on a regular schedule as otherwise agreed to by the Parties.

(i) Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between the systems, shared on the earlier of the identification of the potential impact, within 30 days of such request by the other Party, or on a regular schedule as otherwise agreed to by the Parties.

(j) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

(k) Load flow and short-circuit data initially will be exchanged in PSS/E format. To the extent practical the maintenance and exchange of power system modeling data will be implemented through databases. When feasible, transmission maps and breaker diagrams will be provided in an electronic format agreed upon by the Parties. Formats for the exchange of other data will be agreed upon by the Parties from time to time.

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9.3 **Coordinated System Planning.**

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

9.3.1 **Single Party Planning.**

Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents the procedures, methodologies, and business rules utilized in preparing and completing the report. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, the identification of proposed transmission system enhancements that may affect the Parties’ respective systems.

9.3.2 **Coordinated System Plan.**

The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.5. The Coordinated System Plan shall have as input the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1 (k), the Coordinated System Plan may be integrated into any Joint Coordinated System Plan engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such Joint Coordinated System Plan.

9.3.3 **Analysis of Interconnection Requests.**
In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies and Network Upgrades will include the following:

(a) Upon either the posting to the OASIS of a request for interconnection or the review of study results related to that request for interconnection, the Party receiving the request ("direct connect system") will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the direct connect system will notify the other Party and convey the information provided in the posting.

(b) Following the results of either the Feasibility Study or the System Impact Study, the direct connect system will notify the other Party if the study shows potential reliability concerns on the other Party’s system. After reviewing the results, if the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate and mutually agree on the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party, who will perform the studies. If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV. The Parties will strive to minimize the costs associated with the coordinated study process.

(c) Any coordinated studies will be performed in accordance with the study scope and timeline mutually agreed to in 9.3.3 (b) above utilizing the responsibility options outlined in 9.3.3 (d) below.

(d) The potentially impacted Party may participate in the coordinated study at the System Impact Study or Feasibility Study stage by providing input to the studies to be performed by the direct connect system. If the constraints found require infrastructure additions to mitigate them, then the potentially impacted Party will perform its own Facilities Study as part of the direct connect Party’s Facilities Study. The study cost estimates indicated in the study agreement between the direct connect system and the interconnection customer will reflect the costs and the associated roles of the study participants including the potentially impacted Party. The direct connect system will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

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

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

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

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

(i) In addition, thermal and reactive impacts associated with circulation and other phenomena that result from interconnection and impact the systems of both Parties will be evaluated in the evaluation of specific requests associated with delivery service and in the development of the Coordinated System Plan.

(j) Each Party will maintain a separate interconnection queue. The JRPC will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. The JRPC will post this listing on the Internet site maintained for the communication of information related to the coordinated system planning process. The Internet site will contain links to the web sites of each Party where individual interconnection study results will be maintained.

9.3.4 Analysis of Long-Term Firm Transmission Service Requests.

In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.
Upon either the posting to the OASIS of a request for service or the review of studies related to the evaluation of that service request, the Party receiving the request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the request will notify the other Party and convey the information provided in the posting.

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

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

During the System Impact Study, the potentially impacted system may participate in the coordinated study either by providing input to the studies to be performed by the Party receiving the request. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request’s Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

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

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

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

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

9.3.5 Development of the Coordinated System Plan.

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

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

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties’ systems due to such system additions or Network Upgrades; and

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

9.3.5.2 Coordination of studies required for the development of the Coordinated System Plan will include the following steps:

(a) Every three years, the Parties shall perform a comprehensive, coordinated regional transmission expansion planning study.
Sensitivity analyses will be performed, as required, during the off years based on a review by the JRPC and IPSAC of discrete reliability problems or operability issues that arise due to changing system conditions. Ad hoc study groups may be formed as needed to address localized seams issues, or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented, (e.g., a set number of meetings per year and/or develop a protocol for the exchange of studies, report queues, and other relevant information). Projects needed to resolve transmission problems which have been identified by either RTO at any time during the three year planning cycle will be evaluated by the JRPC at least annually for purposes of testing against the Cross-Border cost allocation criteria. Transmission plans to resolve problems will be identified, included in the respective plans of the RTOs and will be presented to the respective RTO Boards for approval and implementation using each RTOs procedures for approval. Critical upgrades for which the need to begin development is urgent will be presented to the RTO Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be presented to the RTO Boards in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. Each RTO reserves the right to identify required transmission upgrades to their Board for approval at any time.

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

(c) The JRPC will develop a scope and procedure for the inter-regional planning assessment. The scope of the study will include evaluations of the transmission system against the reliability criteria, operational performance criteria, and economic performance criteria applicable to each Party. Each Party will provide a baseline model that includes all transmission enhancements included in the party’s regional transmission expansion plan, and all of the committed interconnection projects and any associated Network Upgrades.

(d) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC.
Exchange of power flow models will be in a format that is acceptable to both Parties and will use a consistent bus numbering convention and bus naming convention to minimize work that is needed to merge detailed power flow models.

(e) The study will initially evaluate the reliability of the combined transmission systems. Any Network Upgrades required to resolve criteria violations will be agreed upon and included in an updated baseline model.

(f) The performance of the combined transmission systems will be tested against agreed upon operational and economic criteria, where applicable, using the updated baseline model. Network Upgrades required to resolve operational and/or economic performance criteria violations will be included in the Coordinated System Plan.

(g) Economic criteria applicable to either Party will be developed and filed by that Party with input from its stakeholders.

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Section 9.4 Allocation of Costs of Network Upgrades Version: 0.0.0 Effective: 9/17/2010

9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.
When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Parties’ Order 2003 compliance filings as accepted by FERC.

9.4.2 Network Upgrades Associated with Transmission Service Requests.
When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Parties’ Order 2003 compliance filings as accepted by FERC.

9.4.3 Network Upgrades Under Coordinated System Plan.
The Coordinated System Plan will identify cross-border projects as (i) CBBRP; or (ii) CBMEP. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet website of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.3.1 Criteria for Project Designation as a Cross-Border Allocation Project:
Projects will be designated in accordance with the following criteria:

9.4.3.1.1 Criteria for Project Designation as a Cross-Border Baseline Reliability Project: Projects that meet all of the following criteria will be designated as CBBRPs: (i) by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria; (ii) the project must be a baseline reliability project as defined under the Midwest ISO or PJM Tariffs; (iii) the resulting allocation of Project Cost to the RTO in which the project is not constructed must be a minimum of $10,000,000; (iv) using the Coordinated System Plan power flow model, the contribution of the cross-border RTO to loading on the constrained facility giving rise to the CBBRP must be at least five
percent (5%) of the total loading on the constrained facility; and (v) the CBBRP must have an in-service date after December 31, 2007. The Cross-Border Grandfathered Projects document contains a list of projects that will be excluded from designation as a CBBRP notwithstanding the in-service date.

9.4.3.1.2 Criteria for Project Designation as a Cross-Border Market Efficiency Project

Projects that meet all of the following criteria will be designated as a CBMEP if the project: (i) has an estimated Project Cost of $20,000,000 or greater; (ii) is evaluated as part of a Coordinated System Plan or joint study process, as described in section 9.3.5 of the JOA; (iii) meets the threshold benefit to cost ration as prescribed under the terms of, and using the benefit and cost measures prescribed under section 9.4.3.1.2.1 of the JOA; (iv) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a Regionally Beneficial Project under the terms of Attachment FF of the Midwest ISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM RTEP or Midwest ISO OATT shall apply the Project Cost of the CBMEP and not the allocated cost; and (v) addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.

9.4.3.1.2.1 Determination of Benefits to Each RTO from CBMEP

The RTOs shall jointly evaluate the benefits to the combined Midwest ISO and PJM markets, and to each market individually, by evaluating multiple metrics using a multi-year analysis to determine whether a proposes project qualified as a CBMEP. The RTOs shall perform this evaluation as follows:

a. The RTOs shall utilize a benefit metric to analyze the anticipated annual economic benefits of construction of a proposed CBMEP to Transmission Customers of each RTO. Benefits are measured for a project by the estimated change in the benefit metric with and without the incorporation of the proposed project. The benefit metric is based upon the impact of the project on: (1) APC (adjusted to account for purchases and sales) and (2) NLP. The benefit metric for each RTO shall be developed by weighting the APC benefit and the NLP benefit. The benefit metric shall be calculated as the sum of seventy percent (70%) times the change in APC benefit for each RTO plus thirty percent (30%) times the change in NLP benefit for each RTO where the change in APC and NLP is calculated by subtracting the APC and NLP values determined without the proposed CBMEP:

\[
\text{Benefit Metric} = (70\% \text{ of change in APC} + 30\% \text{ of change in NLP})
\]
The APC for each RTO represents each RTO’s production costs adjusted for interchange purchases and sales. For each simulation hour in which an RTO is selling interchange, the APC shall be calculated by multiplying the interchange sales MW times the RTO’s generation-weighted LMP and then subtracting this value from the RTO’s production cost. For each simulation hour in which an RTO is purchasing interchange, the APC shall be calculated by multiplying the interchange purchase MW times the RTO’s load-weighted LMP and then adding this value to the RTO’s production cost.

The NLP benefit for each RTO represents each RTO’s gross load payment minus the estimated value of congestion-hedging transmission rights in each RTO. The NLP shall be calculated by multiplying the LMP at each modeled load bus in the RTO by the load (in MW) at the bus, for each simulation hour (load LMP * load (in MW)), and then subtracting from that product the estimated value of congestion-hedging transmission rights for that hour. For each simulation hour, the value of an RTO’s transmission rights shall be calculated by subtracting the RTO generation-weighted LMP from the RTO load-weighted LMP and then multiplying this difference times the lower of the RTO’s total generation MW level or the RTO’s total load MW level.

The benefit metric shall be calculated for each RTO for each year of simulation. Benefits for intermediate years between simulated years will be based on interpolation. The annual benefit for a CBMEP shall be determined as the sum of the benefit values for each RTO. The total project benefit shall be determined by calculating the present value of annual benefits for, at a minimum, the first ten years of project life after the projected in-service year, with a maximum planning horizon of 20 years from the current year.

b. The RTOs shall employ a threshold benefits-to-costs ratio test to evaluate a potential CBMEP. Only projects that meet the benefits-to-costs ratio threshold shall be designated as a CBMEP. The costs applied in the benefits-to-costs ratio shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the CBMEP are determined from the estimated CBMEP installed costs and the fixed charge rate applicable to the constructing transmission owner(s).

The benefits-to-costs ratio threshold for a project to qualify as a CBMEP shall be 1.25 to 1. To determine the present value of the annual benefits and costs, the discount rate shall be based on the
transmission owners’ most recent after-tax embedded cost of capital weighted by each transmission owner’s total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner’s most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

c. Using the cost allocated to each RTO pursuant to section 9.4.3.2.2 of the JOA, and the Coordinated System Plan model, including using the same simulation years, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a Regionally Beneficial Project under the terms of Attachment FF of the Midwest ISO OATT.

9.4.3.2 Cross-Border Project Shares:

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

9.4.3.2.1 Cost Allocation for Cross-Border Baseline Reliability Projects

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

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

9.4.3.2.2 Cost Allocation for Cross-Border Market Efficiency Projects

For CBMEP’s that meet all of the qualifications in section 9.4.3.1.2, 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 9.4.3.1.2.1.a.

9.4.3.3 Determination of Cross-Border Cost Allocation Share Outside of Coordinated System Plan:

Either RTO may request that a project be tested against the cross-border cost allocation criteria during the interim periods between periodic formal releases of the Coordinated System Plan. The RTOs will conduct reviews between the formal cycles on at least an annual basis. Such tests will be performed on the best available joint planning model, as determined by the JRPC.

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

9.4.3.4 Cost Recovery of Cross-Border Allocation Shares:

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

9.4.3.5 Transmission Owners Filing Rights:

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

9.4.3.6 Amendments:

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

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Section 9.5 Agreement to Enforce Duties to Construct and Own Version: 0.0.0

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9.5 Agreement to Enforce Duties to Construct and Own.
To obtain Network Upgrades under this Article IX, PJM will enforce obligations to construct and own or finance enhancements or additions to transmission facilities in accordance with the Transmission Owners Agreement, PJM Interconnection, L.L.C. First Revised Rate Schedule FERC No. 29, the West Transmission Owners Agreement, PJM Interconnection, L.L.C. Rate Schedule FERC No. 33, as either may be amended or restated from time to time, and Midwest ISO will enforce obligations to construct enhancements or additions to transmission facilities in accordance with the Agreement of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, as it may be amended or restated from time to time.

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10.1 Scheduling Checkout Protocols.

10.1.1 Scheduling Protocols.

Each Party will leverage technology to perform electronic approvals of schedules and to perform electronic checkouts. The Parties will follow the following 
scheduling protocols:

10.1.1.1 Each Party, acting as the scheduling agent for its respective BAs, will conduct all 
checkouts with first tier BAs. A first tier BA is any BA that is directly connected 
to any Party’s members’ BA or any BA operated by an independent transmission 
company.

10.1.1.2 The Parties will require all schedules, other than reserve sharing or other 
emergency events, to be tagged in accord with the NERC tagging standard. For 
reserve sharing and other emergency schedules that are not tagged, the Parties 
will enter manual schedules after the fact into their respective scheduling systems 
to facilitate checkout between the Parties.

10.1.1.3 When there is a scheduling conflict, the Parties will work in unison to modify the 
schedule as soon as practical. If there is a scheduling conflict that is identified 
before the schedule has started, then both Parties will make the correction in real-
time and not wait until the quarter hour. If the schedule has already started and 
one Party identifies an error, then the Parties will make the correction at the 
earliest quarter hour increment. If a scheduling conflict cannot be resolved 
between the Parties (but the source and sink have agreed to a MW value), then the 
Parties will both adjust their numbers to that same MW value. If source and sink 
are unable to agree to a MW value, then the previously tagged value will stand for 
both Parties.

10.1.1.4 For BAs or associated scheduling agents that do not use the respective Parties’ 
electronic scheduling interfaces, the Parties will contact entities by telephone to 
perform checkouts. When performing checkouts by telephone, each entity will 
verbally repeat the numerical NSI value to ensure accuracy.

10.1.1.5 The Parties will perform the following types of checkouts:

(a) Pre-schedule (day-ahead) daily between 1600 and 2000 (Eastern 
Prevailing Time) hours:
(i) Intra-hour checkout/schedule confirmation will occur as required due to intra-hour scheduled changes.

(b) Hourly Before the Fact (real-time):

(i) Checkout for the next hours shall be net scheduled. Import and export totals may also be verified in addition to NSI if it is deemed necessary by either party. The Parties may checkout individual schedules if deemed necessary by either party.

(ii) Checkout for the top of the next hour is performed during the last half of the current hour.

(c) Daily after the fact checkout shall occur no later than ten (10) business days after the fact (via email or mutually agreed upon method).

(d) Monthly after the fact checkout shall occur no later than one (1) month after the fact (via phone or mutually agreed upon method).

10.1.1.6
The Parties will require that each of these checkouts be performed with first tier BAs. If a checkout discrepancy is discovered, the Parties will use the NERC tag to determine where the discrepancy exists. The Parties will require any entity that conducts business within its RC Area to checkout with the applicable Party using NERC tag numbers; special naming convention used by that entity or other naming conventions given to schedules by other entities will not be permitted.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE XI ADDITIONAL COORDINATION PROVISIONS Version: 0.0.0 Effective: 9/17/2010

ARTICLE XI
ADDITIONAL COORDINATION PROVISIONS

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 11.1 Application of Congestion Management Process Version: 0.0.0

Effective: 9/17/2010

11.1 Application of Congestion Management Process.

The Parties have agreed to certain operating protocols under this Agreement to ensure system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. These protocols include the Congestion Management Process and applicable NERC reliability plans. As addressed in Section 3.1, the Parties expect that these systems and the operating protocols applicable to these systems will change and revisions to this Agreement will be required from time to time.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 11.2 Additional Provisions Concerning Market-to-Market Version: 0.0.0

Effective: 9/17/2010


11.2.1 LMP Calculation Consistency.

The Parties agree to ensure that LMP signals meet certain common criteria in order to achieve maximum benefits to competition from the Joint and Common Market. In particular, the Parties agree that dispatch in both markets will be performed under a nodal pricing regime and that settlement will be based, in part, on the resulting LMPs. Given the importance of the individual LMPs, the pricing methodologies employed will result in prices that meet certain common criteria at all relevant physical interfaces between the two markets. The Parties’ goal will be that the respective prices calculated by both Parties for these interfaces will be identical. Therefore, to the extent that such prices are not identical, the Parties agree to work in good faith to resolve the reasons for the differences in order to send the most consistent economic signals reasonably possible to all market participants.

The Parties further agree that the LMP formulation will be such that the optimal solution will be very close to the current system operating condition. Inputs into the Locational Marginal Pricing program will be the flexible generating units from the LMP Preprocessor, actual generation, load and system topology from the State Estimator, and binding constraints from the LMP Contingency Processor. The Parties agree to work in good faith to reach resolution on the frequency of the calculation of the prices. Additionally, the Parties agree that any changes to the pricing methodology will be coordinated across the two markets to maintain consistency.

11.2.2 Coordination Processes.

As the Midwest ISO market and the PJM market have evolved over time, it has become critical to coordinate the LMP-based congestion management procedures between the two markets. The market-to-market transmission congestion processes and the LMP at the market border points must be coordinated in order to efficiently manage interregional power flows. This coordination process will ensure appropriate LMP values at the market borders and will eliminate potential inefficiencies and gaming opportunities that otherwise could be caused by uncoordinated congestion management between the adjacent markets.

11.2.3 Market-to-Market Coordination Process.

The fundamental philosophy of the market-to-market transmission congestion coordination process is to allow any transmission constraints that are significantly impacted by generation dispatch changes in both markets to be
jointly managed in the security-constrained economic dispatch models of both Parties. This joint management of transmission constraints near the market borders will provide a more efficient and lower cost transmission congestion management solution and will also provide coordinated pricing at the market boundaries.

This market-to-market coordination process builds upon the Parties’ market-to-non-market coordination process, as described in the “Congestion Management Process” document. The set of transmission Flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market is identified as the set of RCFs. These RCFs are then monitored to measure the impact of Market Flows and loop flows from adjacent regions. The “Congestion Management Process” document provides a framework for calculating the resulting powerflow impacts resulting from the market-based economic dispatch in one region on the transmission facilities in an adjacent region and vice versa (Market Flow impacts). In addition, the “Congestion Management Process” document describes how the Market Flow impacts will be managed on an interregional basis within the existing IDC to enhance the effectiveness of the NERC interregional congestion management process. Lastly, the “Congestion Management Process” document also describes a process for calculating flow entitlement for network and firm transmission utilization in one region on the RCFs in an adjacent region.

The market-to-market coordination process builds on the processes, as described above, by adapting the coordination, as appropriate, to the conditions that will prevail after the Parties’ markets are implemented in the Midwest. In addition, there is a continuing need to define the flow entitlement for network and firm transmission utilization in one region on the RCFs in an adjacent region.

The Parties shall utilize the Interregional Coordination Process on all market-to-market Flowgates that experience congestion. The Party that is responsible for a Flowgate will initiate and terminate the market-to-market process with the other Party. Anytime the Party that is responsible for a Flowgate is binding on that Flowgate to manage congestion, the responsible Party will implement the market-to-market process to utilize the more cost effective generation between the two markets to manage the congestion. The only exception when the market-to-market process is not used will occur when a market-to-market Flowgate is being used as a substitute Flowgate for another limit that is not a market-to-market Flowgate.

The market-to-market process described in the Interregional Coordination Process will normally be performed as needed in the real-time market, however if the need for congestion relief assistance is predictable on a day-ahead basis, the foregoing process will be implemented in the day-ahead market.
The market-to-market settlement process that is applied to both real-time and day-ahead usage is described in the Interregional Coordination Process.

11.2.4 Settlement of Interregional Transactions (via Proxy Buses).

In order for the market-to-market coordination to function properly, the proxy bus models for the Parties must be coordinated to the same level of granularity. The proxy bus modeling approaches must be the same at the market borders.

The proxy bus models will be based on using a flow-weighted average pricing model at common tie points at the market borders. In the day-ahead market and in the FTR models, the flow-weighted proxy bus definitions will be used at all times. In the real-time market, if the scheduled flow and actual flow are consistent at the proxy bus location, then the flow-weighted average price will be utilized. If significant loop flows exist at any of the proxy bus border point locations then the proxy bus price will be changed to reflect actual real-time flow patterns.

11.2.5 Auction Revenue Rights Allocation and Financial Transmission Rights Auction Coordination.

The allocation ARR and auction of FTR products in each marketplace must recognize the Flowgate entitlement that exists in adjacent markets. The ARR allocation/FTR auction model will essentially contain exactly the same level of detail for adjacent regions as the day-ahead market model and the real-time market model. Each Party will allocate ARRs or auction FTRs to the eligible market participants subject to a clearing process that determines the amount of transmission capability that exists to support the FTRs/ARRs.

The ARR allocation/FTR auction clearing process for each Party will model that Party’s flow entitlement on the transmission Flowgates in the adjacent region as the powerflow limit that must be respected in the ARR allocation/FTR auction process. The transmission Flowgates in each Party will be modeled in the clearing process at a capability value equal to the Flowgate rating minus the flow entitlement that exists for flows from the adjacent market. In this way, the ARR allocation/FTR awards across both Parties will recognize the reciprocal transmission utilization that exists for eligible market participants in both markets.

11.2.6 Evolution of the Market-to-Market Coordination Process.

Nothing in this Agreement will preclude the Parties from further evolving their market-to-market coordination process in conjunction with input from their respective market monitors.

11.2.7 Coordinated Emergency Generation Redispatch.

The Parties shall follow a least-cost dispatch protocol in response to system emergencies that will mitigate or stabilize the system emergency in appropriate time to prevent IROL violation, and the costs thereof shall be reflected in, and compensated through, relative LMP values. However, in the event that costs not
cognizable under LMP are incurred, the Party within which the affected resources are located shall reimburse such resource for direct incremental cost, subject to inter-RTO reimbursement in the event that the costs incurred by one Party were caused by a system emergency in the other Party.

Additionally, in the absence of the need to coordinate congestion or address a system emergency, a Party shall be entitled to request that the other Party dispatch a generation unit, subject to the Parties’ agreement with respect to compensation for the dispatch.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE XII EFFECTIVE DATE Version: 0.0.0 Effective: 9/17/2010

ARTICLE XII
EFFECTIVE DATE

12.1
The Parties agree to file this Agreement jointly with FERC on or before December 31, 2003 and to cooperate with each other as necessary and appropriate to facilitate such filing. In that filing, the Parties shall request FERC to approve an effective date 60 days after filing (“Effective Date”).

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE XIII
JOINT RESOLUTION OF MARKET MONITOR ISSUES

In addition to, as otherwise already provided in this Agreement, the Parties agree to address the matters raised and recommendations contained in a filing that the Parties’ respective Market Monitors made on July 28, 2003 in Docket No. EL03-35-002, in response to the FERC order issued in Midwest Independent Transmission System Operator, Inc., 103 FERC ¶ 61,210.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 14.1 Administration of Agreement Version: 0.0.0 Effective: 9/17/2010

14.1 Administration of Agreement.
The ISC shall perform the following with respect to this Agreement:

(a)  Meet no less than once annually to determine whether changes to this Agreement would enhance reliability, efficiency, or economy and to address other matters concerning this Agreement as either Party may raise.

(b)  Conduct additional meetings upon Notice given by either Party, provided that the Notice specifies the reason for the requested meeting.

(c)  Establish task forces and working committees as appropriate to address any issues a Party may raise in furtherance of the objectives of this Agreement.

(d)  Conduct dispute resolution in accordance with this Article.

(e)  Initiate process reviews at the request of either Party for activities undertaken in the performance of this Agreement.

The ISC shall have the authority to make decisions on issues that arise during the performance of the Agreement based upon consensus of the Parties’ representatives thereto.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 14.2 Dispute Resolution Procedures Version: 0.0.0 Effective: 9/17/2010

14.2 Dispute Resolution Procedures.
The Parties shall attempt in good faith to achieve consensus with respect to all matters arising under this Agreement and to use reasonable efforts through good faith discussion and negotiation to avoid and resolve disputes that could delay or impede either Party from receiving the benefits of this Agreement. These dispute resolution procedures apply to any dispute that arises from either Party's performance of, or failure to perform, this Agreement and which the Parties are unable to resolve prior to invocation of these procedures.

14.2.1 Step One.
In the event a dispute arises, a Party shall give written notice of the dispute to the other Party. Within ten (10) days of such Notice, the ISC shall meet and the Parties will attempt to resolve the Dispute by reasonable efforts through good faith discussion and negotiation. Each Party shall also be permitted to bring no more than two (2) other individuals to ISC meetings held under this step as subject matter experts; however, all representatives must be employees of the Party they represent. In addition, if the Parties agree that legal representation would be useful in connection with a meeting, each Party may bring two (2) attorneys (who need not be employees of the Party they represent). In the event the ISC is unable to resolve within twenty (20) days of such Notice, either Party shall be entitled to invoke Step 2.

14.2.2 Step Two.
A Party may invoke Step 2 by giving Notice thereof to the ISC. In the event a Party invokes Step 2, the ISC shall, in writing, and no later than five (5) days after the Notice, refer the dispute in writing to the Parties' Presidents for consideration. The Parties' Presidents shall meet in person no later than fourteen (14) days after such referral and shall make a good faith effort to resolve the dispute. The Parties shall serve upon each other, written position papers concerning the dispute, no later than forty-eight (48) hours in advance of such meeting. In the event the Parties' Presidents fail to resolve the dispute, either Party shall be entitled to invoke Step Three.

14.2.3 Step Three.
Upon the demand of either Party, the dispute shall be referred to the FERC's Office of Dispute Resolution for mediation, and upon a Party's determination at any point in the mediation that mediation has failed to resolve the dispute, either Party may seek formal resolution by initiating a proceeding before the FERC.

14.2.4 Exceptions.
In the event of disputes involving Confidential Information, infringement or ownership of Intellectual Property or rights pertaining thereto, or any dispute where a Party seeks temporary or preliminary injunctive relief to avoid alleged immediate and irreparable harm, the procedures stated in Section 14.2 and its subparts shall apply but shall not preclude a Party from seeking such temporary or preliminary injunctive relief, provided, that if a Party seeks such judicial relief but fails to obtain it, the Party seeking such relief...
shall pay the reasonable attorneys’ fees and costs of the other Party incurred with respect to opposing such relief.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE XV RELATIONSHIP OF THE PARTIES

Version: 0.0.0 Effective: 9/17/2010

ARTICLE XV
RELATIONSHIP OF THE PARTIES

15.1 Relationship Between this Agreement and Joint and Common Market Agreement.
The Parties agree that execution of this Agreement will further enable the Parties to address many of the specific tasks that are required prior to the creation of a joint and common market between the Parties. Specifically, Articles III through XI of this Agreement detail certain assignments that may pertain to the joint and common market. To ensure efficient handling of tasks hereunder and under the Joint and Common Market Agreement, the Parties hereby agree as follows:

15.1.1 Avoiding Duplication of Efforts.
The Parties agree that to the extent that the tasks specified in Articles III through XI of this Agreement are duplicative of projects being pursued under the Joint and Common Market Agreement, the Parties will utilize this Agreement to pursue those assignments to minimize duplicative efforts. The Parties therefore agree that the Joint and Common Market Agreement will be deemed to be superseded by this Agreement only to the extent necessary to accomplish the assignments in Articles III through XI.

15.1.2 Making Necessary Amendments to the Joint and Common Market Agreement.
The Parties agree to amend the Joint and Common Market Agreement to carry out the purposes of Section 15.1.1 within thirty (30) days after the Effective Date of this Agreement, to the extent amendment may be required under the terms of the Joint and Common Market Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE XVI ACCOUNTING AND ALLOCATION OF COSTS OF JOINT OPERATIONS

16.1 Revenue Distribution.
This Agreement does not modify any FERC approved agreement between a Party and the owners of the transmission facilities over which the Party exercises control with regard to revenue distribution. All distribution of revenue received under this Agreement shall be distributed by the Party receiving such revenue in accordance with the terms of such Party’s agreement with the transmission owners.

16.2 Billing and Invoicing Procedures.
Except as specifically set forth in this Agreement, each Party shall render invoices to the other Party for amounts due under this Agreement in accordance with its customary billing practices (or as otherwise agreed between the Parties) and payment shall be due in accordance with the invoicing Party’s customary payment requirements (unless otherwise agreed). All payments shall be made in immediately available funds payable to the invoicing Party by wire transfer pursuant to instructions set out by the Parties from time to time. Interest on any amounts not paid when due shall be calculated in accordance with the methodology specified for interest on refunds in the Commission’s regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

16.3 Access to Information by the Parties.
Each Party grants the other Party, acting through its officers, employees and agents such access to the books and records of the other as is necessary to audit and verify the accuracy of charges between the Parties under this Agreement. Such access to records shall be at the location of the Party whose books and records are being reviewed pursuant to this Agreement and shall occur during regular business hours.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
ARTICLE XVII RETAINED RIGHTS OF THE PARTIES Version: 0.0.0 Effective: 9/17/2010

17.1  Parties Entitled to Act Separately.
This Agreement does not create or establish, and shall not be construed to create or establish, any partnership or joint venture between the Parties. This Agreement establishes terms and conditions solely of a contractual relationship, between two independent entities, to facilitate the achievement of the joint objectives described in the Agreement. The contractual relationship established hereunder implies no duties or obligations between the Parties except as specified expressly herein. All obligations hereunder shall be subject to and performed in a manner that complies with each Party’s internal requirements; provided, however, this sentence shall not limit either Party’s payment obligation under Article XVI or indemnity obligation under Section 18.3.1 or Section 18.3.2, respectively.

17.2  Agreement to Jointly Make Required Tariff Changes to Implement Agreement.
The Parties agree that they shall cooperate in good faith in the filing of any Section 205 filings before FERC that may be required to implement the terms of this Agreement, including revisions to a Party’s OATT as necessary to implement Sections 6.2, 6.3, 9.4.1, and 9.4.2 of this Agreement. Whenever practicable, the Parties agree that they shall make simultaneous filings with FERC concerning such tariff filings.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE XVIII ADDITIONAL PROVISIONS Version: 0.0.0 Effective: 9/17/2010

ARTICLE XVIII
ADDITIONAL PROVISIONS

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 18.1 Confidentiality Version: 0.0.0 Effective: 9/17/2010

18.1 Confidentiality.

18.1.1 Definition. The term “Confidential Information” shall mean: (a) all information, whether furnished before or after the mutual execution of this Agreement, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked “confidential” or “proprietary” or which under all of the circumstances should be treated as confidential or proprietary; (b) any information deemed confidential under some other form of confidentiality agreement or tariff provided to a Party by a generator; (c) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any Confidential Information; (d) applicable material deemed Confidential Information pursuant to the PJM Data Confidentiality Regional Stakeholder Group, and (e) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC’s Standards of Conduct set forth in 18 C.F.R. § 37, et seq. and the Parties’ Standards of Conduct on file with the FERC.

18.1.2 Protection. During the course of the Parties’ performance under this Agreement, a Party may receive or become exposed to Confidential Information. Except as set forth herein, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing Party. In addition, each Party shall ensure that its employees, its subcontractors and its subcontractors’ employees and agents to whom Confidential Information is exposed agree to be bound by the terms and conditions contained herein. Each Party shall be liable for any breach of this Section by its employees, its subcontractors and its subcontractors’ employees and agents.

This obligation of confidentiality shall not extend to information that, at no fault of the recipient Party, is or was (1) in the public domain or generally available or known to the public; (2) disclosed to a recipient by a third party who had a legal right to do so; (3) independently developed by a Party or known to such Party prior to its disclosure hereunder; and (4) which is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel, in which event the recipient hereby agrees to provide the issuing Party with prompt Notice of such request or requirement in order to enable the issuing Party to (a) seek an appropriate protective order or other remedy, (b) consult with the recipient with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. In the event that such protective order or other remedy is not obtained, or that the issuing Party waives compliance with the provisions hereof, the recipient hereby agrees to furnish only that portion of the Confidential Information which the recipient’s counsel advises is legally required and to exercise best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.
18.1.3 Confidential Data Exchange.
The Parties agree that various components of the data exchanged under Article IV, are Confidential Information and that, in addition to the protections of Confidential Information provided under Section 18.1.2

(a) The Party receiving the Confidential Information shall treat the information in the same confidential manner as its Governing Documents require it treat the confidential information of its own members and market participants.

(b) The receiving Party shall not release the producing Party’s Confidential Information until expiration of the time period controlling the producing Party’s disclosure of the same information, as such period is described in the producing Party’s Governing Documents from time to time. As of the Effective Date, this period is six (6) months with respect to bid or pricing data and seven (7) calendar days for transmission data after the event ends.

(c) All other prerequisites applicable to the producing Party’s release of such Confidential Information have been satisfied as determined by the producing Party.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 18.2 Protection of Intellectual Property Version: 0.0.0 Effective: 9/17/2010

18.2 Protection of Intellectual Property.

18.2.1 Unauthorized Transfer of Third-Party Intellectual Property.
In the performance of this Agreement, no Party shall transfer to the other Party any Intellectual Property the use of which by the other Party would constitute an infringement of the rights of any third party. In the event such transfer occurs, whether or not inadvertent, the transferring Party shall, promptly upon learning of the transfer, provide Notice to the receiving Party and upon receipt of Notice shall take reasonable steps to avoid claims and mitigate losses.

18.2.2 Intellectual Property Developed Under this Agreement.
In the event in the course of performing this Agreement the Parties mutually develop any new Intellectual Property that is reduced to writing, the Parties shall negotiate in good faith concerning the ownership and licensing thereof.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 18.3 Indemnity Version: 0.0.0 Effective: 6/16/2011

18.3 Indemnity.

18.3.1 Indemnity of Midwest ISO.
PJM will defend, indemnify and hold the Midwest ISO harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively “Losses”), brought or obtained by third parties against the Midwest ISO, only to the extent such Losses arise directly from:

(a) Gross negligence, recklessness, or willful misconduct of PJM or any of PJM’s agents or employees, in the performance of this Agreement, except to the extent the Losses arise (i) from gross negligence, recklessness, willful misconduct or breach of contract or law by the Midwest ISO or any of the Midwest ISO’s agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon the Midwest ISO or the Midwest ISO’s agents or employees;

(b) Any claim that PJM violated any copyright, patent, trademark, license, or other intellectual property right of a third party in the performance of this Agreement;

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 18.2.1; or

(d) Any claim that PJM caused bodily injury to an employee of the Midwest ISO due to negligence, recklessness, or willful conduct of PJM.

18.3.2 Indemnity of PJM.
The Midwest ISO will defend, indemnify and hold PJM harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively “Losses”), brought or obtained by third parties against PJM, only to the extent such Losses arise directly from:

- Gross negligence or recklessness, or willful misconduct of Midwest ISO or any of Midwest ISO’s agents or employees, in the performance of the Agreement, except to the extent the Losses arise (i) from gross negligence, recklessness, willful misconduct or breach of contract or law by PJM or any of PJM’s agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon PJM or PJM’s agents or employees;

- Any claim that the Midwest ISO violated any copyright, patent, trademark, license, or other intellectual property right of a third party in the performance of this Agreement;
Any claim arising from the transfer of Intellectual Property in violation of Section 18.2.1; or

Any claim that the Midwest ISO caused bodily injury to an employee of PJM due to negligence, recklessness, or willful conduct of Midwest ISO.

18.3.3 Damages Limitation.

18.3.3.1
Except for amounts required to be paid under Article 16.2 by one Party to the other under this Agreement, and except for amounts due under Sections 18.3.1 and 18.3.2, no Party shall be liable to the other Party, directly or indirectly, for any damages or losses of any kind sustained due to any failure to perform this Agreement, unless such failure to perform was malicious or reckless. The limitation of liability shall not apply to billing adjustments for errors in invoiced amounts due under this Agreement, provided such billing adjustments are made within the claims limitation period under Section 18.3.4 of this Agreement.

18.3.3.2
Except for amounts required to be paid by one Party to the other under this Agreement, and except for amounts due under Sections 18.3.1 and 18.3.2, any liability of a Party to the other Party hereunder shall be limited to direct damages as qualified by the following sentence. No lost profits, damages to compensate for lost goodwill, consequential damages, or punitive damages shall be sought or awarded.

18.3.4 Limitation on Claims

No claim seeking an adjustment in the billing for any service, transaction, or charge under this Agreement may be asserted with respect to a month, if more than one year has elapsed since the first date upon which the invoice was rendered for the billing for that month. A Party shall make no adjustment to billing with respect to a month for any service, transaction, or charge under this Agreement, if more than one year has elapsed since the first date upon which the invoice was rendered for the billing for that month, unless a claim seeking such adjustment had been received by the Party prior thereto, provided, however, that no adjustments to billing or resettlement shall be made for any claims asserted within the first year following the date of the filing of the Settlement Agreement and Offer of Settlement (“Settlement”) in Docket Nos. EL10-45 et al. for any time period prior to the date of filing of the Settlement.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
18.4 Effective Date and Termination Provision.

The term of this Agreement commences as provided in Section 12.1. The Agreement shall terminate and cease to be effective upon FERC acceptance of the mutual agreement by the Parties to terminate the Agreement or other FERC order terminating the Agreement. Nothing in this Agreement shall prejudice the right of either Party to seek termination of this Agreement under Section 206 of the Federal Power Act, or successor section or statute thereof.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 18.5 Survival Provisions Version: 0.0.0 Effective: 9/17/2010

18.5 Survival Provisions.
Upon termination or expiration of this Agreement for any reason or in accordance with its terms, the following Articles and Sections shall be deemed to have survived such termination or expiration:

- Article II - (Abbreviations, Acronyms and Definitions)
- Article XVI - (Accounting and Allocation of Costs of Joint Operations)
- Article XVII - (Retained Rights of the Parties)
- Article XVIII - (Additional Provisions), except Section 18.11 (Execution of Counterparts) and Section 18.12 (Amendment)

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 18.6 No Third-Party Beneficiaries Version: 0.0.0 Effective: 9/17/2010

18.6 No Third-Party Beneficiaries.
This Agreement is intended solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on, any third party (other than the Parties’ successors and permitted assigns).

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 18.7 Successors and Assigns Version: 0.0.0 Effective: 9/17/2010

18.7 Successors and Assigns.
This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns permitted herein, but shall not be assigned except (a) with the written consent of the non-assigning Party, which consent may be withheld in such Party’s absolute discretion; and (b) in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party’s assets. In the case of any merger, consolidation, reorganization, sale, or spin-off by a Party, the Party shall assure that the successor or purchaser adopts this Agreement and, the other Party shall be deemed to have consented to such adoption.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
18.8 Force Majeure.

No Party shall be in breach of this Agreement to the extent and during the period such Party’s performance is made impracticable by any unanticipated cause or causes beyond such Party’s control and without such Party’s fault or negligence, which may include, but are not limited to, any act, omission, or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities. Upon the occurrence of an event considered by a Party to constitute a force majeure event, such Party shall use reasonable efforts to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event, provided that this Section shall require no Party to settle any strike or labor dispute.

A Party claiming a force majeure event shall notify the other Party in writing immediately and in no event later forty-eight (48) hours after the occurrence of the force majeure event. The foregoing notwithstanding, the occurrence of a cause under this Section shall not excuse a Party from making any payment otherwise required under this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 18.9 Governing Law Version: 0.0.0 Effective: 9/17/2010

18.9 Governing Law.
This Agreement shall be interpreted, construed and governed by the applicable federal law and the laws of the state of Delaware without giving effect to its conflict of law principles.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
18.10 Notice.

Whether expressly so stated or not, all notices, demands, requests and other communications required or permitted by or provided for in this Agreement (“Notice”) shall be given in writing to a Party at the address set forth below, or at such other address as a Party shall designate for itself in writing in accordance with this Section, and shall be delivered by hand or reputable overnight courier:

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403-2947
Attention: General Counsel

Midwest Independent Transmission System Operator, Inc.

For Parcels:
701 City Center Drive
Carmel, Indiana 46032
Attention: General Counsel

For U.S. Mail:
P.O. Box 4202
Carmel, Indiana 46082-4202
Attention: General Counsel

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
18.11 Execution of Counterparts.
This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon the Parties hereto, notwithstanding that both Parties may not have executed the same counterpart.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
Section 18.12 Amendment Version: 0.0.0 Effective: 9/17/2010

18.12 Amendment.
Except as may otherwise be provided herein, neither this Agreement nor any of the terms hereof may be amended unless such amendment is in writing and signed by the Parties and such amendment has been accepted by the FERC.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE XIX VOLTAGE CONTROL AND REACTIVE POWER COORDINATION

Version: 0.0.0 Effective: 9/17/2010
Section 19.1 Coordination Objectives Version: 0.0.0 Effective: 9/17/2010

19.1 Coordination Objectives.
Each Party acknowledges that voltage control and reactive power coordination are essential to promote reliability. Therefore, the Parties establish procedures (“Voltage and Reactive Power Coordination Procedures”) under this Article by which they shall conduct such coordination.

19.1.1 Contents of Voltage and Reactive Power Coordination Procedures.
The Voltage and Reactive Power Coordination Procedures address the following components: (a) procedures to assist the Parties in maintaining a wide area view of interconnection conditions by enhancing the coordination of voltage and reactive levels throughout their RTO footprints; (b) procedures to ensure the maintenance of sufficient reactive reserves to respond to scenarios of high load periods, loss of critical reactive resources, and unusually high transfers; and (c) procedures for sharing of data with other neighboring RCs for their analysis and coordinated operation.

19.1.2 The Parties will review the Voltage and Reactive Power Coordination Procedures from time to time to make revisions and enhancements as appropriate to accommodate additional capabilities or changes to industry reliability requirements.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
19.2 Voltage and Reactive Power Coordination Procedures
The Parties will utilize the following procedures to coordinate the use of voltage control equipment to maintain a reliable bulk power transmission system voltage profile on their respective systems.

19.2.1 Under normal conditions, each Party will coordinate with the Transmission Owners, the TOPs and the BAs as necessary and feasible to supply its own reactive load and losses at all load levels.

19.2.2 Voltage schedule coordination is the responsibility of each Party. Generally, the voltage schedule is determined based on conditions in the proximity of generating stations and EHV stations with voltage regulating capabilities. Each Party works with its respective Transmission Owners, TOPs, and BAs to determine adequate and reliable voltage schedules considering actual and post-contingency conditions.

19.2.3 Each Party will establish voltage limits at critical locations within its own system and exchange this information with the other Party. This information shall include normal high voltage limits, normal low voltage limits, post-contingency emergency high voltage limits and post-contingency emergency low voltage limits, and, shall identify the voltage limit value (if available) at which load shedding will be implemented.

19.2.4 Each Party will maintain awareness of the voltage limits in the other Party’s area (where the EMS Model includes sufficient detail to permit this) and awareness of outages and potential contingencies that could result in violation of those voltage limits.

19.2.5 The Parties will utilize the following voltage support level definitions for pre- or post-contingency conditions in the development of RTO-coordinated voltage support requests:

19.2.5.1 Emergency Heavy. This support is necessary when there is an actual low voltage situation due to high loads, heavy transfers, or a critical contingency.

19.2.5.2 Heavy. This support is necessary in anticipation of high loads or heavy transfers in order to prevent the occurrence of low voltage situations that could result in transfer curtailments.

19.2.5.3 Normal On-Peak.
Reactive support is needed to supply normal loads during peak conditions. No unusually high loads or transfers are expected.

19.2.5.4 **Normal Off-Peak.**
Reactive support is needed for normal loadings during non-peak conditions. No minimum loads or transfers are expected.

19.2.5.5 **Light.**
Reactive support is necessary to avoid high voltage due to anticipated minimum load or transfer conditions.

19.2.5.6 **Emergency Light.**
Reactive support is needed when there is an actual high voltage situation due to minimum loads, transfers, and/or critical contingency.

19.2.6 Each Party shall maintain a list of actions that are taken for each level of voltage support listed in Section 19.2.5. The following outlines some of the actions a Party can take to respond to anticipated or prevailing system conditions.

19.2.6.1 **Emergency Heavy.**

(i) Ensure capacitors are in service;
(ii) Reduce generation, as possible, to maximize reactive output on all units in area of concern;
(iii) Supply maximum VAR generation (if practical reduce generation to increase reactive output);
(iv) Adjust EHV tap changers to maximize reactive support to the EHV systems;
(v) Reduce transfers.

19.2.6.2 **Heavy.**

(i) Check all bulk power capacitors;
(ii) Request Transmission Owners’ dispatchers to verify that all capacitors are in service;
(iii) Adjust EHV tap changers to increase reactive support to the EHV system;
(iv) Increase generator VAR output to increase support of EHV voltage;
(v) Maximum reactive output on all EHV generating units, at current MW loading level and within current operating restrictions.

19.2.6.3 **Normal On-Peak.**
(i) Bring on capacitors to maintain reactive reserve on generation units;
(ii) Adjust TCUL transformer set-points to keep capacitors in service;
(iii) Hold on-peak voltage schedule at all generating stations;
(iv) Follow normal on-peak voltage schedules;
(v) Operate capacitors and EHV transformers to tune system voltage.

19.2.6.4 Normal Off-Peak.

(i) Switch off capacitors as necessary to keep generators at unity or lagging Power Factor;
(ii) Hold off-peak voltage schedule at all generating stations.

19.2.6.5 Light.

(i) Deviate from off-peak voltage schedule at generation stations to reduce system voltage without exceeding normal station limits;
(ii) Request Transmission Owners to switch out all underlying capacitors;
(iii) Switch out bulk power capacitors;
(iv) Operate pumped storage generation in pumping mode;
(v) Adjust EHV transformers so that the EHV system voltages reach their maximum limits simultaneously;
(vi) Request Transmission Owners to adjust available subtransmission and distribution transformers so that both the high and low side reach maximum voltage limits simultaneously;
(vii) With advance warning, impose contractual minimums;
(viii) Allow generating units to operate with leading power factor.

19.2.6.6 Emergency Light.

(i) Open select EHV lines as studies and conditions permit.

19.2.7 Periodic Meetings.

As part of seasonal preparations, the Parties will conduct meetings to discuss issues due to the anticipated conditions and determine any actions that may be required in response to voltage concerns. The Parties will provide the voltage schedule information on an annual basis to ensure that the information is current.

19.2.8 Additional Coordination.

In concert with the coordination of Outages addressed in Article VII and the Parties’ respective day-ahead security analysis processes, the Parties will coordinate the impact of outages and system conditions on the voltage/reactive profile. Coordination will include the following elements:

19.2.8.1
Each Party will review its forecasted loads, transfers, and all information on available generation and transmission reactive power sources at the beginning of each shift.

19.2.8.2
Within the range of Normal On-Peak and Normal Off-Peak, each Party will operate independently in accordance with the above stated criteria and any individual system guidelines for the supply of the Party’s reactive power requirements.

19.2.8.3
If either Party anticipates reactive problems after the review, it may request joint implementation of Heavy or Light reactive support levels under these Voltage and Reactive Power Coordination Procedures, as it deems appropriate to the situation. When a Party calls for a particular level of support to be implemented under these procedures, it or the applicable TOP/BA must identify the time it will start adjusting its system, the support level it is implementing, and the voltage problem area.

19.2.8.4
If a Party experiences an actual low or high voltage condition after initial reactive support measures are taken, then the emergency reactive support level is implemented for the area experiencing the problem. The Party will also notify applicable RCs as soon as feasible. In addition, the Voltage and Reactive Power Coordination Procedures are to be consulted to determine if further action is necessary to correct an undesirable voltage situation.

19.2.9 Voltage Schedule Coordination
The Parties will coordinate the use of voltage control equipment to maintain a reliable bulk power transmission system voltage profile on the the Parties’ systems, and surrounding systems. Providing reactive power and proper voltage support to a large interconnected power system is an iterative process. Reactive support starts at the distribution and sub-transmission levels as load increases, substation capacitors are switched, tap changing transformers, and generating unit MVAR outputs are adjusted in concert to hold overall system voltage levels. In general, the voltage schedules are determined by the local TOP based on the local design characteristics and equipment availability. The following procedures are intended to ensure that bulk systems voltage levels enhance system reliability.

19.2.9.1 Specific Voltage Schedule Coordination Actions.

(a) Each Party has operational or functional control of reactive sources within its system and will direct adjustments to voltage schedules at appropriate facilities.
(b) Each Party generally will adjust its voltage schedules to best utilize its resources for operation prior to coordinated actions with the other Party.

(c) If a Party anticipates voltage or reactive problems, it will inform the other Party (operations planning with respect to future day and RC with respect to same day) of the situation, describe the conditions, and request voltage/reactive support under these Procedures. As a part of the request, the Party must identify the specific area where voltage/reactive support is requested and provide an estimate of the magnitude and time duration of the request as well as the specific requirements for reactive support. The Parties will determine the appropriate measures to address the condition and develop a plan of action.

(d) Each Party will contact its affected Transmission Owner/TOP/BA. The purpose of this call is to ensure that the situation is fully understood and that an effective operating plan to address the situation has been developed. If necessary the Parties will convene a conference call with the affected Transmission Owners TOPs, and BAs.

(e) Each Party will implement or direct voltage schedule changes requested by the other Party, provided that a Party may decline a requested change if the change would result in equipment violations or reduce the effective operation of its facilities. A Party that declines a requested change must inform the requesting Party that the request cannot be granted and state the reason for denial.

19.2.10 Voltage/Reactive Transfer Limits.

19.2.10.1 Each Party has wide area transfer interfaces where a MW surrogate is used to control voltage collapse conditions. In cases where the potential for collapse (or cascading) is identified, prompt voltage support and MW generation adjustments may be needed. Where coordinated effort is required for voltage stability interfaces, generation adjustment requests to avoid voltage collapse or cascading conditions must be clearly communicated and implemented promptly. Using these limits the Parties will implement the following real-time coordination:

(a) At 95% of Interface Limit

(i) A Party which observes the reading shall call the other Party. Regardless of which Party sees the 95% level reached, both Parties will immediately re-run their analyses to verify results.
(ii) The monitoring Party with the preponderance of the flows will notify other RCs via the RCIS.

(iii) The Parties will contact the affected TOP/BAs to discuss reactive outputs and adjustments required.

(iv) The applicable Party takes appropriate actions, which may include re-dispatching generation and directing schedule curtailments.

(b) Exceeding Interface Limit

(i) The Party observing the reading will declare an emergency.

(ii) That Party will inform other RCs of the emergency.

(iii) The applicable Party will take immediate action, which may include generation redispatch, ordering immediate schedule curtailments, and, if required, load shedding.

19.2.10.2 Where feasible, and if both Parties’ EMS models have sufficient detail, each Party will attempt to duplicate the other Party’s wide area transfer interface evaluation in order to provide backup limit calculation in the event that the primary Party is unable to accurately determine the appropriate reliability limits.

19.2.10.3 If a new wide area transfer interface is determined to exist and detailed modeling does not exist for the interface, the Parties will coordinate to determine how their models need to be enhanced and to determine procedures for coordination in furtherance of the enhancement.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ARTICLE XX CHANGE MANAGEMENT PROCESS Version: 0.0.0 Effective:

6/16/2011

ARTICLE XX
CHANGE MANAGEMENT PROCESS

20.1 Notice. Prior to making a change to any processes that would affect the implementation of the market-to-market process under this Agreement, including the determination of market-to-market settlements, the Party desiring the change shall notify the other Party in writing or via email of the proposed change. The notice shall include a complete and detailed description of the proposed change, the reason for the proposed change, and the impacts the proposed change will have on the implementation of the market-to-market process, including market-to-market settlements under this Agreement.

20.2 Response to Notice. Within a reasonable time after receipt of the Notice described in Section 20.1, the receiving Party shall: (a) notify in writing or by email the other Party of its concurrence with the proposed change; (b) request in writing or via email additional documentation from the other Party, including associated test documentation; (c) notify in writing or via email the other Party of its disagreement with the proposed change and request that issue regarding the proposed change be addressed pursuant to the dispute resolution procedures set forth in Article XIV of this Agreement. In the event that the receiving Party requests additional documentation as described in (b), within a reasonable time after receipt of such information, it shall notify the other Party in writing or via email that it concurs with the change or that it requests dispute resolution pursuant to Article XIV of this Agreement.

20.3 Implementation of Change. The Party proposing a change to its market-to-market implementation process shall not implement such change until it receives written or email notification from the other Party that the other Party concurs with the change or until completion of any dispute resolution process initiated pursuant to Article XIV of this Agreement. Neither Party shall unduly delay its obligations under this Article XX so as to impede the other Party from timely implementation of a proposed change.

20.4 Summary of Proposed Changes. On a quarterly basis, the Parties shall post on their respective websites a summary of market-to-market implementation process changes proposed by the Parties in the prior quarter and the status of such changes.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
ARTICLE XXI BIENNIAL REVIEW OF PROCESS CHANGES Version: 0.0.0 Effective: 6/16/2011

21.1 Biennial Review. Commencing two years after the issuance of the Baseline Review Report described in the Settlement Agreement and Offer of Settlement (“Settlement”) filed in Docket Nos. EL10-45-000 et al. and every two years thereafter, the Parties shall conduct a comprehensive review of the changes made to each Party’s processes used to implement this Agreement since the previous biennial review, or in the case of the first biennial review, changes made since the issuance of the Baseline Review Report.

21.2 Posting of Biennial Review. The Parties shall post the results of each biennial review on their respective websites.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

PJM INTERCONNECTION, L.L.C.

By: [Signature]
Name: Richard A. Wodyka
Title: Senior Vice President – RTO Coordination and Integration
Date: December 31, 2003

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

By: [Signature]
Name: James P. Pergerson
Title: President and Chief Executive Officer
Date: ________________________

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ATTACHMENT 2 CONGESTION MANAGEMENT PROCESS (CMP) MASTER

Version: 0.0.0 Effective: 6/16/2011

Midwest ISO
Second Revised Rate Schedule FERC No. 5
PJM Interconnection, L.L.C.
Second Revised Rate Schedule FERC No. 38

ATTACHMENT 2

Congestion Management Process (CMP) MASTER

Baseline Version 1.9

January 4, 2011

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
**Executive Summary**

This Congestion Management Process document provides significant detail in the areas of Market Flow Calculation. These additional details are the result of discussions between multiple Operating Entities.

As Operating Entities expand and implement their respective markets, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional) will interact to ensure that parallel flows and impacts are recognized and controlled in a manner that consistently ensures system reliability. This proposed solution will greatly enhance current Interchange Distribution Calculator (IDC) granularity by utilizing existing real-time applications to monitor and react to Flowgates external to an Operating Entity’s footprint.

In brief, the process includes the following concepts:

1. **Participating Operating Entities** will agree to observe limits on an extensive list of coordinated external Flowgates.

2. **Like all Control Areas (CA), Market-Based Operating Entities** will have Firm Market Flows upon those Flowgates.

3. **Market-Based Operating Entities** will determine Firm Market Flows and constrain their operations to limit Firm Market Flows on the Coordinated Flowgates to no more than the calculated Firm Flow Limit established in the analysis.

4. **In real-time, Market-Based Operating Entities** will calculate and monitor one-hour projected and actual flows.

5. **Market-Based Operating Entities** will post to the IDC the actual and the one-hour ahead projected market flow, consisting of the Firm Market Flow and the additional Non-Firm Market Flow, for both internal and external Coordinated Flowgates.

6. **Market-Based Operating Entities** will provide to the IDC detailed representation of their marginal units, so that the IDC can continue to effectively compute the effects of all tagged transactions regardless of the size of the market area. These tagged transactions will include transactions into the market, transactions out of the market, transactions through the market, and tagged grandfathered transactions within the market.

7. **When there is a Transmission Loading Relief (TLR) 3a request or higher called on a Coordinated Flowgate, and the Market-Based Operating Entity’s actual/one-hour ahead projected Market Flows exceed the Firm Flow Limits, Market-Based Operating Entities will respond to their relief obligations by redispaching their systems in a manner that is consistent with how non-market entities respond to their share of Network and Native Load (NNL) relief obligations per the IDC congestion management report.**
17 Because the IDC will have the real-time/one-hour ahead projected flows throughout the Market-Based Operating Entity’s system (as represented by the impacts upon various Coordinated Flowgates), the effectiveness of the IDC will be greatly enhanced.

18 The above processes refer to the “Congestion Management” portion of the paper, which will be implemented by Market-Based Operating Entities.

19 Additional entities may choose to enter into similar Reciprocal Coordination Agreements that describe how Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), Firm Flows, and outage maintenance will be coordinated on a forward basis.

(i) The complete process will allow participating Operating Entities to address the reliability aspects of congestion management seams issues between all parties whether the seams are between market to non-market operations or market-to-market operations.

Effective Date: 9/17/2010 - Docket #: ER10-2746-003
Change Summary

Generate baseline Congestion Management Process (CMP) document based on CMP documents executed by:

d. Manitoba Hydro and the Midwest ISO
e. MAPPCOR and the Midwest ISO
f. The Midwest ISO and PJM
g. The Midwest ISO, PJM and TVA
h. The Midwest ISO and SPP

The document also includes subsequent changes agreed upon by a majority of the Congestion Management Process Council (CMPC). For items which are specific to a limited number of agreements, the CMP members have used an approach of documenting these unique items in separate appendices rather than in the base document. The CMPC members reserve all rights with respect to the different options identified in the appendices attached hereto without any obligation to adopt or support such options. The CMPC members reserve the right to oppose any position taken by another CMPC member in a FERC filing or otherwise with respect to the choice of options listed in the appendices. Nothing contained herein shall be construed to indicate the support or agreement by the CMPC members to an option presented in the appendices.

Revision 1.1 (November 30, 2007)

Per FERC Order ER07-1417-000, in the “Forward Coordination Processes” section 6.6 added the word “outage” between “unit” and “scheduling” in the following sentence, “Market-Based Operating Entities will use the Flowgate limit to restrict unit outage scheduling for a Coordinated Flowgate when maintenance outage coordination indicates possible congestion and there is recent TLR activity on a Flowgate.”

Revision 1.2 (May 2, 2008)

The Market Flow Threshold is changing from 3% to 5%. The NERC Standards Committee approved changing the Market Flow Threshold for the field test at their April 10, 2008 meeting.

Revision 1.3 (July 16, 2008)

Per FERC Order issued in Docket Nos. ER08-884-000 and ER08-913-000, Appendix H (Market Flow Threshold Field Test Terms And Conditions) was added.
Revision 1.4 (October 31, 2008)

The percentages were changed in Sections 4.4 (Firm Market Flow Calculation Rules) and 5.5 (Market-Based Operating Entity Real-time Actions) to be consistent with changes made under Revision 1.2. Appendix H – Market Flow Threshold Field Test Terms And Conditions was updated to reflect the NERC approved Market Flow Threshold Field Test extension to October 31, 2009.

Revision 1.5 (December 18, 2008)

Updated Section 5.2 (Quantify and Provide Data for Market Flow) and Appendix B – Determination of Marginal Zone Participation Factors to support changes to the manner in which the Midwest ISO uses marginal zones and submits marginal zone information to the IDC.

Revision 1.6 (February 19, 2009)

Appendix H – Market Flow Threshold Field Test Terms And Conditions was updated to reflect that Midwest ISO no longer has a contractual obligation to observe a 0% threshold for Midwest ISO market flows on Flowgates where both MAPP and the Midwest ISO are reciprocal.

Revision 1.7 (November 1, 2009)

Applied updates based on the results of the Market Flow Threshold Field Test including clarifications that allocations are calculated down to zero percent. Changes have been applied to the Executive Summary, Section 4.1 Market Flow Determination, Section 4.4 Firm Market Flow Calculation Rules, Section 5.5 Market-Based Operating Entity Real-time Actions, Section 6.6 Forward Coordination Processes, Section 6.6.3 Limiting Firm Transmission Service, Section 6.7 Sharing or Transferring Unused Allocations, and Appendix H – Application of Market Flow Threshold Field Test Conditions.

Revision 1.8 (May 31, 2010)

Applied updates to further standardize the “Allocation Adjustment for Net Transmission Facilities and/or Designated Network Resources” process. Changes have been made to Appendix F – FERC Dispute Resolution and Appendix G – Allocation Adjustments for New Transmission Facilities.

Revision 1.9 (January 4, 2011)

Modified to incorporate the revisions to the JOA, including revisions to Attachments 2 and 3, submitted as part of the Settlement Agreement and Offer of Settlement in Docket Nos. EL10-45-000, EL10-46-000, and EL10-60-000. Effective Date: 6/16/2011 - Docket #: ER11-3979-000
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Effective Date: 9/17/2010 - Docket #: ER10-2746-003
Section 1 – Introduction

It is the intention of the Reciprocal Entities to utilize the processes within this document. It is further the intention to develop this process in a way that will allow other regional entities with similar concerns to utilize the concepts within this process to aid in the resolution of their own seams issues.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
**Section 1.1 Problem Definition Version: 0.0.0 Effective: 9/17/2010**

1.1 Problem Definition

1.1.1 The Nature of Energy Flows

Energy flows are distinctly different from the manner in which the energy commodity is purchased, sold, and ultimately scheduled. In the current practice of “contract path” scheduling, schedules identify a source point for generation of energy, a series of wheeling agreements being utilized to transport that energy, and a specific sink point where that energy is being consumed by a load. However, due to the electrical characteristics of the Eastern Interconnection, energy flows are more dispersed than what is described within that schedule. This disconnect becomes of concern when there is a need to take actions on contract-path schedules to effect changes on the physical system (for example, the curtailment of schedules to relieve transmission constraints).

In the Eastern Interconnection, much of this concern has been addressed through the use of the North American Electric Reliability Corporation (NERC) and/or North American Energy Standards Board (NAESB) TLR process. Through this process, Reliability Coordinators utilize the IDC to determine appropriate actions to provide that relief. The IDC bases its calculations on the use of transaction tags: electronic documents that specify a source and a sink, which can be used to estimate real power flows through the use of a network model. In order to change flows, the IDC is given a particular constraint and a desired change in flows. The IDC returns all source to sink transactions that contribute to that constraint and specifies schedule changes to be made that will effect that change in flows.

In other parts of the Eastern Interconnection, however, the use of centralized economic dispatch results in a solution that does not focus on changing entire transactions (effectively redispatching through the use of imbalance energy), but rather redispatch itself. In this procedure, the party attempting to provide relief does not need to know that a balanced source to sink transaction should be adjusted; rather, they are aware of a net generation to load balance and the impacts of different generators on various constraints. Bid-based security constrained central dispatch based on Locational Marginal Pricing is a regional implementation of this practice.

Currently, these two practices are somewhat incompatible. Due to the electrical characteristics of the Interconnection and geographic scope of the regions, this incompatibility has been of limited concern. However, regional market expansion has begun to draw attention to this operational disjoint, as the expansion itself exacerbates the negative effects of the incompatibility.

1.1.2 Granularity in the IDC

The IDC uses an approximation of the Interconnection to identify impacts on a particular transmission constraint that are caused by flows between Control Areas. This approximation allows for a Reliability Coordinator to identify tagged transactions with specific sources and
sinks that are contributing to the constraint. While tagged transactions may specify sources and sinks in a very specific manner, the IDC in general cannot respect this detail, and instead consolidates the impacts of several generators and loads into a homogenous representation of the impacts of a single Control Area. This is referred to as the \textit{granularity} of the IDC. Current granularity is typically defined to the Control Area level; finer granularity is present in certain special situations as deemed necessary by NERC.

\subsection*{1.1.3 Reduced Data and Granularity Coarseness}

As centrally dispatched energy markets expand their footprint, two related changes occur with regard to the above process. In some cases, data previously sent to the IDC is no longer sent due to the fact that it is no longer tagged. In others, transactions remain tagged, but the increased market footprint results in an increase in granularity coarseness within the IDC; that is, the apparent Control Area boundary becomes the same as the market boundary so that what had been historically 30 or more Control Areas now appears as one.

In the first change, transactions contained entirely within the market footprint are considered to be utilizing network service (even when the market spans multiple Control Areas). As such, there is no requirement for them to be tagged (or such requirement is waived by NERC), and therefore, no requirement that they be sent to the IDC. This is of concern from a reliability perspective, as the IDC will no longer have a large pool of transactions from which to provide relief, although the energy flows may remain consistent with those prior to the market expansion. In other words, flows subject to TLR curtailment prior to the market expansion are no longer available for that process.

In the second change, the expansion of the footprint itself results in a dilution of the approximation utilized by the IDC. When a market region is relatively small (or isolated), the Control Area to Control Area approximation of that region’s impact on transmission constraints is acceptable; actions within the market footprint generally have a similar and consistent impact on all transmission facilities outside the footprint. However, when the market footprint expands significantly, and is co-mingled with non-market Control Areas, the ability to utilize the historic approximation of electrically representative flows fails to effectively predict energy flow. Impacts on external facilities can vary significantly depending on the dispatch of the resources within the market footprint. With regard to the IDC, this information is effectively lost within the expanded footprint, and results in an increase in the level of granularity coarseness, or a “loss of granularity.”

\subsection*{1.1.4 Accounting for Loop Flows}

The processes for accounting for loop flows caused by uses of the transmission system between Control Areas are different under a market environment. Absent a market, loop flows from Transmission Service reservations between Control Areas are identified and accounted for by importing transmission reservations from surrounding systems. Under a market environment, the market will not have explicit transmission reservations for evolving market dispatch conditions between market Control Areas. Thus, a mechanism for accounting for anticipated Market Flows on non-market systems is necessary.
1.1.5 Conclusion

The net effect of these changes is that reliability must be managed through different processes than those used before the market region’s expansion. While relief can still be requested using the current process, both the ability to predict the effectiveness of a curtailment to provide that relief and the general pool of transactions available for curtailment are reduced. This congestion management process (CMP) offers a strategy for eliminating this concern through a process that provides more information (finer granularity) to the NERC IDC for the market area. This new congestion management process will ensure that reliability is not adversely affected as markets expand by providing information and relief opportunities previously unavailable to the IDC.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
1.2 Process Scope and Limitations

1.2.1 Vision Statement

As Operating Entities become Market-Based Operating Entities, and expand their various markets, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional TLR) will interact to ensure parallel flows and impacts are recognized and controlled in a manner that consistently ensures system reliability and equitability. Reliability Coordinators can mandate emergency procedures to maintain safe operating limits, however, without coordination agreements that maintain flow limits in advance, the market would become volatile and the burden for relieving excess flow would ignore the economics of the entities which would be required to redispach. For these entities, this process will offer a manner in which Market-Based Operating Entities can coordinate parallel flows with Operating Entities that have not yet or do not contemplate implementing markets. This process will provide more proactive management of transmission resources, more accurate information to Reliability Coordinators, and more candidates for providing relief when reliability is threatened due to transmission overload conditions.

1.2.2 Process Scope

This process has been written specifically with the goal of coordinating seams between Reciprocal Entities and their respective neighbors.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
This document focuses on a solution to meet the following goals and requirements:

1. Develop a congestion management process whereby transmission overloads can be prevented through a shared and effective reduction in Flowgate or constraint usage by Reciprocal Entities and adjoining Reliability Coordinators.

2. Agree on a predefined set of Flowgates or constraints to be considered by all Reciprocal Entities, and a process to maintain this set as necessary.

3. Determine the best way to calculate flow due to market impacts on a defined set of Flowgates.

4. Develop Reciprocal Coordination Agreements that establish how each Operating Entity will consider its own Flowgate or constraint usage as well as the usage of other Operating Entities when it determines the amount of Flowgate or constraint capacity remaining. This process will include both operating horizon determination as well as forward looking capacity allocation.

5. Develop a procedure for managing congestion when Flowgates are impacted by both tagged and untagged energy flow.

6. Develop a procedure for determining the priorities of untagged energy flows (created through parallel flows from the market).

7. Agree on steps to be taken by Operating Entities to unload a constraint on a shared basis.

8. Determine whether procedure(s) for managing congestion will differ based on where the Flowgate is located (i.e., inside Reciprocal Entity A, inside Reciprocal Entity B, or outside both Reciprocal Entity A and Reciprocal Entity B).

9. Confirm that the solution will be equitable, transparent, auditable, and independent for all parties.

10. Develop methodology to preserve and accommodate grandfathered transmission rights, contract rights, and other joint-use agreements.

11. Develop methodology to address changes in Total Transfer Capability (TTC), such as future system topology changes, new Designated Network Resources (DNRs), facility uprates/derates, prior outage limitations, etc., with respect to Allocation implications.

12. Develop a methodology for releasing Allocations if other parties do not join the process or if there is ATC going unused.

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1.4 Assumptions

The processes set forth in this document were based on the following assumptions:

c. Point-to-point schedules sinking in, sourcing from, or passing through a Market-Based Operating Entity will be tagged.

d. The IDC or a similar repository of schedules is needed at the Interconnection’s current state and for the foreseeable future.

e. The Market-Based Operating Entity can compute the impacts of the untagged market dispatch on the Flowgates as currently required by the IDC.

f. The Market-Based Operating Entity’s Energy Management System (EMS) has the capability to monitor and respond to real-time and projected flows created by its real-time dispatch.

g. The Reliability Coordinator of the area in which a Flowgate exists will be responsible for monitoring the Flowgate, determining any amount of relief needed, and entering the required relief in the IDC.

h. The IDC has been modified to accept the calculated values of the impact of real-time generation in order to determine which schedules require curtailment in conjunction with the required Market-Based Operating Entity’s redispatch.

i. The IDC can calculate the total amount of MW relief required by the Market-Based Operating Entity (schedule curtailments required plus the relief provided by redispatch).

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Section 2 Process Overview Version: 0.0.0 Effective: 9/17/2010

Section 2 – Process Overview

2.1 Summary of Process

In order to coordinate congestion management, a bridge must be established that provides for comparable actions between Operating Entities. Without such a bridge, it is difficult, if not impossible, to ensure reliability and system coordination in an efficient and equitable manner. To effect this coordination of congestion management activities, we propose a methodology for determining both firm and non-firm flows resulting from Market-Based Operating Entity dispatch on external parties’ Flowgates.

Market Flows are defined as the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity’s market. (Note: For the purposes of the Reciprocal Coordination process discussed later, Firm Transmission Service (7F) will be combined with the untagged firm component of Market Flows in the calculation of Historic Firm Flow. The Historic Firm Flow is described later in this document).

Market Flows can be divided into Firm Market Flows and Non-Firm Market Flows. Firm Market Flows are considered as firm use of the transmission system for congestion management.
purposes and will be curtailed on a proportional basis with other firm uses during periods of firm
curtailments and are equivalent to Firm Transmission Service. Non-Firm Market Flows are
considered as non-firm use of the transmission system for congestion management purposes and
will be curtailed on a proportional basis with other non-firm uses during periods of non-firm
curtailments and are equivalent to non-firm Transmission Service. As such, Reliability
Coordinators can request Market-Based Operating Entities to provide relief under TLR based on
these transmission priorities.

By applying the above philosophy to the problem of coordinating congestion management, we
can determine not only the impacts of a Market-Based Operating Entity’s dispatch on a particular
Flowgate; we can also determine the appropriate firmness of those flows. This results in the
ability to coordinate both proactive and reactive congestion management between operating
entities in a way that respects the current TLR process, while still allowing for the flexibility of
internal congestion management based on market prices.

There are two areas that must be defined in order for this process to work effectively:

- **Coordinated Flowgate Definition.** In order to ensure that impacts of dispatch are
  properly recognized, a list of Flowgates must be developed around which congestion
  management may be effected and coordination can be established.

- **Congestion Management.** By coordinating congestion management efforts and
  enhancing the TLR process to recognize both untagged energy flows and data of finer
  granularity, we can ensure that when TLR is called, the appropriate non-firm flows are
  reduced before Firm Flows. This coordination will result in a reduction of TLR 5 events,
  as more relief will be available in TLR 3 to mitigate a constraint. This is accomplished
  through the calculation of flows due to economic dispatch, as well as by providing
  marginal unit information to aid in interchange transaction management.

The next sections of this document discuss each of these areas in detail.

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Section 3 – Impacted Flowgate Determination

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Section 3.1 Flowgates Version: 0.0.0 Effective: 9/17/2010

3.1 Flowgates

Flowgates are facilities or groups of facilities that may act as significant constraint points on the system. As such, they are typically used to analyze or monitor the effects of power flows on the bulk transmission grid. Operating Entities utilize Flowgates in various capacities to coordinate operations and manage reliability. For the purpose of this process, there are three kinds of Flowgates: AFC Flowgates, which are defined in Appendix A, Coordinated Flowgates (CFs), which are defined below, and Reciprocal Coordinated Flowgates (RCFs), which are defined in “Reciprocal Operations” Section 6. A diagram illustrating how these three categories of Flowgates are determined is included as Appendix C.

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Section 3.2 Coordinated Flowgates Version: 0.0.0 Effective: 9/17/2010

3.2 Coordinated Flowgates

An Operating Entity will conduct sensitivity studies to determine which Flowgates are significantly impacted by the flows of the Operating Entity’s Control Zones (historic Control Areas that existed in the IDC). An Operating Entity identifies these Flowgates by performing the following four studies to determine which Flowgates the Operating Entity will monitor and help control. A Flowgate passing any one of these studies will be considered a Coordinated Flowgate. Only AFC Flowgates will be eligible for consideration as Coordinated Flowgates. A Flowgate must have AFCs computed and these AFCs must be used to sell Transmission Service in order to be a Coordinated Flowgate.

An Operating Entity may also specify additional Flowgates that have not passed any of the four studies to be Coordinated Flowgates. For Flowgates on which the Operating Entity expects to utilize the TLR process to protect system reliability, such specification is required. For a list of Coordinated Flowgates between Reciprocal Entities, please see each Reciprocal Entity’s Open Access Same-Time Information System (OASIS) website.

Coordinated Flowgates are identified to determine which Flowgates an entity impacts significantly. This set of Flowgates may then be used in the congestion management processes and/or Reciprocal Operations defined in this document.

When performing the four Flowgate studies, a 5% threshold will be applied on an absolute basis without regard to the positive or negative sign of the impact. Use of a 5% threshold in the studies may not capture all Flowgates that experience a significant impact due to market operations. The Operating Entities have agreed to adopt a lower threshold at the time NERC and/or NAESB implements the use of a lower threshold in the TLR process.

3.2.1 Flowgate Studies

Study 1) – IDC Base Case

(using the IDC tool)

This is a one time study done before Control Area consolidation. The IDC can provide a list of Flowgates for any user-specified Control Area whose GLDF (Generator to Load Distribution Factor (NNL)) impact is 5% or greater. The Operating Entity will use the IDC capabilities to develop a preliminary set of Flowgates. This list will contain Flowgates that are impacted by 5% or greater by the Control Areas that will be joining the Operating Entity as Control Zones/areas. OTDF Flowgates will be analyzed with the contingent element out of service. Using the historic Control Area representation in the IDC (i.e., pre-Operating Entity expansion), if any one generator has a GLDF (Generator to Load Distribution Factor) greater than 5% as determined by the IDC, this Flowgate will be considered a Coordinated Flowgate.

Study 2) – IDC PSS/E Base Case

(no transmission outages – offline study)
For those situations where one or more CAs are being, or have been incorporated into an Operating Entity’s footprint after the freeze date, there will be a generator analysis performed to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. In order to confirm the IDC analysis, and to provide a better confidence that the Operating Entity has effectively captured the subset of Flowgates upon which its generators have a significant impact, an offline study utilizing MUST capabilities will be conducted. The Operating Entity will perform off-line studies (using the IDC PSS/E base case) to confirm the IDC analysis. Study 1 and Study 2 are separate studies. There is no requirement that a Flowgate must pass both studies in order to be coordinated.

Study 3) – IDC PSS/E Base Case

(transaction outage - offline study)

For those situations where one or more CAs are being, or have been incorporated into an Operating Entity’s footprint after the freeze date, there will be a Flowgate analysis performed to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. The Operating Entity, in consultation with affected operating authorities, will perform a prior outage analysis, including both internal and external outages. The Flowgates determined using Study 2 or 4 that have a 3% to 5% distribution factor will be analyzed against prior outage conditions. This study will be performed offline utilizing MUST capabilities. If any Flowgates with a 3% to 5% distribution factor from Study 2 or 4 are impacted by 5% or more from a prior outage condition (Line Outage Distribution Factor LODF) from this method, the Flowgate will be added to the list of Coordinated Flowgates.

Study 4) – Control Area to Control Area

For those situations where one or more CAs are being, or have been incorporated into an Operating Entity’s footprint after the freeze date, there will be a Flowgate analysis performed to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. The Operating Entity will analyze transactions between each new CA and the existing market, as well as between each CA/CA permutation (if more than one CA is moving into the footprint). OTDF Flowgates will be analyzed with the contingent element out of service. This study will use Transfer Distribution Factors (TDFs) from the IDC and offline studies utilizing MUST capabilities. Flowgates that are impacted by greater than 5% as determined by the IDC will be considered a Coordinated Flowgate.

3.2.2 Disputed Flowgates

If a Reciprocal Entity believes that another Reciprocal Entity implementing the congestion management portion of this process has a significant impact on one of their Flowgates, but that Flowgate was not included in the Coordinated Flowgate list, the involved Reciprocal Entities will use the following process.

- If an operating emergency exists involving the candidate Flowgate, the Reciprocal Entities shall treat the facilities as a temporary Coordinated Flowgate prior to the study procedure below. If no operating emergency or imminent danger exists, the study
procedure below shall be pursued prior to the candidate Flowgate being designated as a Coordinated Flowgate.

- The Reciprocal Entity conducts studies to determine the conditions under which the other Reciprocal Entity would have a significant impact on the Flowgate in question. The Reciprocal Entity conducting the study then submits these studies to the other Reciprocal Entity implementing this process. The Reciprocal Entity’s studies should include each of the four studies described above; in addition to any other studies they believe illustrate the validity of their request. The other Reciprocal Entity will review the studies and determine if they appear to support the request of the Reciprocal Entity conducting the study. If they do, the Flowgate will be added to the list of Coordinated Flowgates.

- If, following evaluation of the supplied studies, any Reciprocal Entity still disputes another Reciprocal Entity’s request, the Reciprocal Entity will submit a formal request to the NERC Operations Reliability Subcommittee (ORS) asking for further review of the situation. The ORS will review the studies of both the requesting Reciprocal Entity and the other Reciprocal Entity, and direct the participating Reciprocal Entities to take appropriate action.

3.2.3 Third Party Request Flowgate Additions

Each party shall provide in its stakeholder processes opportunities for third parties or other entities to propose additional Coordinated Flowgates and procedures for review of relevant non-confidential data in order to assess the merit of the proposal. The current procedure for the review and maintenance of Coordinated Flowgates is set forth in Appendix C.

3.2.4 Frequency of Coordinated Flowgate Determination

The determination of Coordinated Flowgates will be performed at the initial implementation of the CMP and then on a periodic basis, as described in Appendix C.

3.2.5 Dynamic Creation of Coordinated Flowgates

For temporary Flowgates developed “on the fly,” the IDC will utilize the current IDC methodology for determining NNL contribution until the Market-Based Operating Entity has begun reporting data for the new Flowgate. Interchange transactions into, out of, or across the Market-Based Operating Entity will continue to be E-tagged and available for curtailment in TLR 3, 4, or 5. Market-Based Operating Entities will study the Flowgate in a timely manner and begin reporting Flowgate data within no more than two business days (where the Flowgate has already been designated as an AFC Flowgate). This will ensure that the Market-Based Operating Entity has the time necessary to properly study the Flowgate using the four studies detailed earlier in this document and determine the Flowgate’s relationship with the Market-Based Operating Entity’s dispatch. For internal Flowgates, the Market-Based Operating Entity will redispatch during a TLR 3 to manage the constraint as necessary until it begins reporting the Firm and Non-Firm Market Flows; during a TLR 5, the IDC will request NNL relief in the same manner as today. Alternatively, for internal and external Flowgates, an Operating Entity may
utilize an appropriate substitute Coordinated Flowgate that has similar Market Flows and tag impacts as the temporary Flowgate. In this case, an Operating Entity would have to realize relief through redispatch and TLR 3. An example of an appropriate substitute would be a Flowgate with a monitored element directly in series with a temporary Flowgate’s monitored element and with the same contingent element. If the Flowgate meets the necessary criteria, the Market-Based Operating Entity will begin to provide the necessary values to the IDC in the same manner as Market Flow values are provided to the IDC for all other Coordinated Flowgates. The necessary criteria for adding a Flowgate are defined in Appendix C. If in the event of a system emergency (TLR 3b or higher) and the situation requires a response faster than the process may provide, the Market-Based Operating Entities will coordinate respective actions to provide immediate relief until final review.

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Market Flows on a Coordinated Flowgate can be quantified and considered in each direction. Market Flow is then further designated into two components: Firm Market Flow, which is energy flow related to contributions from the Network and Native Load serving aspects of the dispatch, and Non-Firm Market Flow, which is energy flow related to the Market-Based Operating Entity’s market operations.

Each Market-Based Operating Entity will calculate their actual real-time and projected directional Market Flows, as well as their directional Firm and Non-Firm Market Flows, on each Coordinated Flowgate. The following sections outline how these flows will be computed.
Section 4.1 Market Flow Determination Version: 0.0.0 Effective: 6/18/2013

4.1 Market Flow Determination

The determination of Market Flows builds on the “Per Generator” methodologies that were developed by the NERC Parallel Flow Task Force. The “Per Generator Method Without Counter Flow” was presented to and approved by both the NERC Security Coordinator Subcommittee (SCS) and the Market Interface Committee (MIC). This methodology is presently used in the IDC to determine NNL contributions.

Similar to the Per Generator Method, the Market Flow calculation method is based on Generator Shift Factors (GSFs) of a market area’s assigned generation and the Load Shift Factors (LSFs) of its load on a specific Flowgate, relative to a system swing bus. The GSFs are calculated from a single bus location in the base case (e.g., the terminal bus of each generator) while the LSFs are defined as a general scaling of the market area’s load. The Generator to Load Distribution Factor (GLDF) is determined through superposition by subtracting the LSF from the GSF.

The determination of the Market Flow contribution of a unit to a specific Flowgate is the product of the generator’s GLDF multiplied by the actual output (in megawatts) of that generator. The total Market Flow on a specific Flowgate is calculated in each direction; forward Market Flows is the sum of the positive Market Flow contributions of each generator within the market area, while reverse Market Flow is the sum of the negative Market Flow contributions of each generator within the market area.

For purposes of the Market Flow determination, the market area may be the entire RTO footprint, as in the following illustration, or it may be a subset of the RTO region, such as a pre-integration NERC-recognized Control Area, as necessary to ensure accurate determinations and consistency with pre-integration flow determinations. In the latter case, the total market flow of an RTO shall be the sum of the flows from and between such market areas.
The Market Flow calculation differs from the Per Generator Method in the following ways:

- The contribution from all market area generators will be taken into account.
- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The Market Flow calculations will use all flows, in both directions, down to a 5% threshold for the IDC to assign TLR curtailments and down to a 0% threshold for information purposes. Forward flows and reverse flows are determined as discrete values.
- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.
By expanding on the Per Generator Method, the Market Flow calculation evolves into a methodology very similar to the “Per Generator Method,” while providing granularity on the order of the most granular method developed by the IDC Granularity Task Force.

Directional flows are required for this process to ensure a Market-Based Operating Entity can effectively select the most effective generation pattern to control the flows on both internal and external constraints, but are considered as distinct directional flows to ensure comparability with existing NERC and/or NAESB TLR processes. Under this process, the use of real-time values in concert with the Market Flow calculation effectively implements one of the more accurate and detailed methods of the six IDC Granularity Options considered by the NERC IDC Granularity Task Force.

Units assigned to serve a market area’s load do not need to reside within the market area’s footprint to be considered in the Market Flow calculation. Units outside of the market area that are pseudo-tied into the market to serve the market area’s load will be considered in the Market Flow calculation. However, units outside of the market area will not be considered when those units will have tags associated with their transfers (i.e., where pseudo-tie does not exist).

Additionally, there may be situations where the participation of a generator in the market that is not modeled as a pseudo-tie may be less than 100% (e.g., a unit jointly owned in which not all of the owners are participating in the market). This situation occurs when the generator output controlled by the non-participating parties is represented as interchange with a corresponding tag(s) and not as a pseudo-tie generator internal to each party’s Control Area. Except for the generator output represented by qualifying interchange transactions from jointly owned units described in the following paragraph, such situations will be addressed by including the generator output in that Market-Based Operating Entity’s Market Flow calculation with the amount of generator output not participating in the market being treated as a slice of system export tagged transaction. This is implemented by assuming that all the generating resources in the RTO contribute proportionally to the interchange (e.g., the export is not assigned to a specific generator).

When a jointly owned unit, which is also listed as a Designated Network Resource for the Historic Firm Flow calculation, participates in more than one market (both of which make a Market Flow calculation), and the generator output from that unit between the two markets is represented as interchange with a corresponding tag(s) and not as a pseudo-tie generator internal to each market’s Control Area, its modeling in the Market Flow calculation will be aligned with that in the Historic Firm Flow calculation. The amount of generator output from that unit scheduled between the two markets will be treated as a unit specific export tagged transaction in the Market Flow calculation of the Market-Based Operating Entity where the generator is located and will be treated as a load specific import tagged transaction in the Market Flow calculation of the other Market-Based Operating Entity.

- For exports out of one market area associated with the jointly owned unit(s), the generator output of jointly owned unit will be scaled down by an amount which is the lesser of the corresponding export tagged transaction(s) and unit ownership of an owner participating in other market area.
For imports into the other market area associated with the jointly owned external unit(s), the Control Zone load or bus load(s) will be scaled down by an amount which is the lesser of the corresponding import tagged transaction(s) and unit ownership of an owner participating in the market area.

Finally, imports into or exports out of the market area, and tagged grandfathered transactions within the market area, must be properly accounted for in the determination of Market Flows. When the actual generation of the market area exceeds the total load of that area, the market area is exporting energy. The exports of tagged transactions must be accounted for in the Market Flow calculation. For export transactions, this will be accomplished within the calculation by including a new term that proportionally offsets the MW output of all unit(s) in the market by the amount of the total market export excluding unit specific tagged transactions. This ensures that the Market Flow calculation is measuring only the effect of internal generation serving internal load.

When the actual generation of the market area is less than the total load of the market area, that area is importing energy. These imports are tagged transactions that must be accounted for in the Market Flow calculation, as “Market Flows” are a measure of internal generation serving internal load. For import transactions, this will be accomplished within the calculations by including a new term that proportionally offsets the MW load of all load buses in the market by the amount of the total market import excluding load specific tagged transactions. The processes currently within IDC will address the counting of these transactions.

Below is a summary of the calculations discussed above.

For a specified Flowgate, the Market Flow impact of a market area is given as:

\[ \text{Total Directional “Market Flows”} = \sum (\text{Directional “Market Flow” contribution of each unit in the Market-Based Operating Entity’s area}), \text{grouped by impact direction} \]

where,

\[ \text{“Market Flow” contribution of each unit in the Market-Based Operating Entity’s area} = (GLDF_{\text{Adj}}) (\text{Adjusted Real-Time generator output}) \]

and,

\[ GLDF_{\text{Adj}} \text{ is the Generator to Load Distribution Factor} \]

Where the generator shift factor (GSF_{\text{Adj}}) uses Adjusted Real-Time generator output and the load shift factor (LSF_{\text{Adj}}) uses Adjusted Real-Time bus loads.

\[ GLDF_{\text{Adj}} = GSF_{\text{Adj}} - LSF_{\text{Adj}} \]

Adjusted Real-Time generator output is the output of an individual generator as reported by the state estimator solution that has been scaled down for exports associated with joint ownership, if any, and then further scaled down proportionally to account for total exports.

Adjusted Real-Time bus load is the sum of all bus loads in the market as reported by the state estimator solution that have been scaled down for imports associated with joint ownership, if any, and then further scaled down proportionally to account for total imports.

The real-time and one-hour ahead projected “Market Flows” will be calculated on-line utilizing
the Market-Based Operating Entity’s state estimator model and solution. This is the same solution presently used to determine real-time market prices as well as providing on-line reliability assessment and the periodicity of the Market Flow calculation will be on the same order. Inputs to the state estimator solution include the topology of the transmission system and actual analog values (e.g., line flows, transformer flows, etc…). This information is provided to the state estimator automatically via SCADA systems such as NERC’s ISN link.

Using an on-line state estimator model to calculate “Market Flows” provides a more accurate assessment than using an off-line representation for a number of reasons. The calculation incorporates a significant amount of real-time data, including:

- **Actual real-time and projected generator output.** Off-line models often assume an output level based on a nominal value (such as unit maximum capability), but there is no guarantee that the unit will be operating at that assumed level, or even on-line. Off-line models may not reflect the impact of pumped-storage units when in pumping mode; these units may be represented as a generator even when pumping. Additionally off-line models may not reflect the impact of units such as wind generators. A real-time calculation explicitly represents the actual operating modes of these units.

- **Actual real-time bus loads.** Off-line assessments may not be able to accurately account for changes in load diversity. Off-line models are often based on seasonal winter and summer peak load base cases. While representative of these peak periods, these cases may not reflect the load diversity that exists during off-peak and shoulder hours as well as off-peak and shoulder months. A real-time calculation explicitly accounts for load diversity. Off-line assessments may also reflect load reduction programs that are only in effect during peak periods.

- **Actual real-time breaker status.** Off-line assessments are often bus models, where individual circuit breakers are not represented. On-line models are typically node models where switching devices are explicitly represented. This allows for the real-time calculation to automatically account for split bus conditions and unusual topology conditions due to circuit breaker outages.

Additionally, the calculation rate of the on-line assessment is much quicker and accurate than an off-line assessment, as the on-line assessment immediately incorporates changes in system topology and generators. Facility outages are automatically incorporated into the real-time assessment.

In order to provide reliable and consistent flow calculations, entities utilizing this process as the basis for coordination must ensure that the modeling data and assumptions used in the calculation process are consistent. Reciprocal Entities will coordinate models to ensure similar computations and analysis. Reciprocal Entities will each utilize real-time ICCP and ISN data for observable areas in each of their respective state estimator models and will utilize NERC data for areas outside the observable areas to ensure their models stay synchronized with each other and the NERC IDC.

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Section 4.2 Firm Flow Determination Version: 0.0.0 Effective: 6/16/2011

4.2 Firm Flow Determination

Firm Market Flows represent the directional sum of flows created by Designated Network Resources serving designated network loads within a particular market area. They are based primarily on the configuration of the system and its associated flow characteristics; utilizing generation and load values as its primary inputs. Therefore, these Firm Market Flows can be determined based on expected usage and the Allocation of Flowgate capacity.

An entity can determine Firm Market Flows on a particular Flowgate using the same process as utilized by the IDC. This process is summarized below:

1. Utilize a reference base case to determine the Generation Shift Factors for all generators in the current Control Areas’ respective footprints to a specific swing bus with respect to a specific Flowgate.

2. Utilize the same base case to determine the Load Shift Factors for the Control Area’s load to a specific swing bus with respect to that Flowgate.

3. Utilize superposition to calculate the Generation to Load Distribution Factors (GLDF) for the generators with respect to that Flowgate.

4. Multiply the expected output used to serve native load from each generator by the appropriate GLDF to determine that generator’s flow on the Flowgate.

5. Sum these individual contributions by direction to create the directional Firm Market Flow impact on the Flowgate.

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4.3 Determining the Firm Flow Limit

Given the Firm Market Flow determinations described in the previous section, Market-Based Operating Entities can assume them to be their Firm Flow Limits. These limits define the maximum value of the Market Flows that can be considered as firm in each direction on a particular Flowgate. Prior to real time, a calculation will be done based on updated hourly forecasted loads and topology. The results should be an hourly forecast of directional Firm Market Flows. This is a significant improvement over current IDC processes, which uses a peak load value instead of an hourly load more closely aligned with forecasted data.

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Section 4.4 Firm Market Flow Calculation Rates Version: 0.0.0 Effective: 9/17/2010

4.4 Firm Market Flow Calculation Rules

The Firm Flow Limits for both 0% Market Flows and 5% Market Flows will be calculated based on certain criteria and rules. The calculation will include the effects of firm network service in both forward and reverse directions. The process will be similar to that of the IDC but will include one set of impacts down to 0% and another set down to 5%. The down to 0% impacts will be used to determine Firm Flow Limits on 0% Market Flows. The down to 5% impacts will be used to determine Firm Flow Limits on 5% Market Flows. The following points form the basis for the calculation.

1. The generation-to-load calculation will be made on a Control Area basis. The impact of generation-to-load will be determined for Coordinated Flowgates.

2. The Flowgate impact will be determined based on individual generators serving aggregated CA load. Only generators that are Designated Network Resources for the CA load will be included in the calculation.

3. Forward Firm Flow Limits for 0% Market Flows will consider impacts in the additive direction down to 0%, and reverse Firm Flow Limits for 0% Market Flows will consider impacts in the counter flow direction down to 0%. Forward Firm Flow Limits for 5% Market Flows will be determined by subtracting impacts between 0% and 5% in the additive direction from the Forward Firm Flow Limit for 0% Market Flows. Reverse Firm Flow Limits for 5% Market Flows will be determined by subtracting the impacts between 0% and 5% in the counter-flow direction from the reverse Firm Flow Limit for 0% Market Flows. Market Flow impacts and allocations using a 5% threshold are reported to the IDC to assign TLR curtailments. Market Flow impacts and allocations using a 0% threshold are reported to the IDC for information purposes.

4. Designated Network Resources located outside the CA will not be included in the generation-to-load calculation if OASIS reservations exist for these generators.

5. If a generator or a portion of a generator is used to make off-system sales that have an OASIS reservation, that generator or portion of a generator should be excluded from the generation-to-load calculation.

6. Generators that will be off-line during the calculated period will not be included in the generation-to-load calculation for that period.

7. CA net interchange will be computed by summing all Firm Transmission Service reservations and all Designated Network Resources that are in effect throughout the calculation period. Designated Network Resources are included in CA net interchange to the extent they are located outside the CA and have an OASIS reservation. The net interchange will either be positive (exports exceed imports) or negative (imports exceed exports).

8. If the net interchange is negative, the period load is reduced by the net interchange.
9. If the net interchange is positive, the period load is not adjusted for net interchange.

10. The generation-to-load calculation will be made using generation-to-load distribution factors that represent the topology of the system for the period under consideration.

11. PMAX of the generators should be net generation (excluding the plant auxiliaries) and the CA load should not include plant auxiliaries.

12. The portion of jointly owned units that are treated as schedules will not be included in the generation-to-load calculation if an OASIS reservation exists.

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Section 5 – Market-Based Operating Entity Congestion Management

Once there has been an establishment of the Firm Flow Limit that is possible given Firm Market Flow calculation, that data will be used in the operating environment in a manner that relates to real time energy flows.

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5.1 Calculating Market Flows

On a periodic basis, the Market-Based Operating Entity will calculate directional Market Flows for all Coordinated Flowgates. These flows will represent the actual flows in each direction at the time of the calculation, and be used in concert with the previously calculated Firm Flow Limits to determine the portion of those flows that should be considered firm and non-firm.

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Section 5.2 Quantify and Provide Data for Market Flow Version: 0.0.0 Effective: 9/17/2010

5.2 Quantify and Provide Data for Market Flow

Every fifteen minutes, the Market-Based Operating Entity will be responsible for providing to Reliability Coordinators the following information:

- Firm Market Flows for all Coordinated Flowgates in each direction
- Non-Firm Market Flows for all Coordinated Flowgates in each direction

The Firm Market Flow (Priority 7-FN) will be equivalent to the calculated Market Flow, up to the Firm Flow Limit. In real time, any Market Flow in excess of the Firm Flow Limit will be reported as Non-Firm Market Flow (Priority 6-NN) (note that under reciprocal operations, some of this Non-Firm Market Flow may be quantified as Priority 2-NH).

This information will be provided for both current hour and next hour, and is used in order to communicate to Reliability Coordinators the amount of flows to be considered firm on the various Coordinated Flowgates in each direction. When the Firm Flow Limit forecast is calculated to be greater than Market Flow for current hour or next hour, actual Firm Flow Limit (used in TLR5) will be set equal to Market Flow.

Additionally, as frequently as once an hour, but no less frequently than once every three months, the Market-Based Operating Entity will submit to the Reliability Coordinator sets of data describing the marginal units and associated participation factors for generation within the market footprint. The level of detail of the data may vary, as different Operating Entities will have different unique situations to address. However, this data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by the Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
Section 5.3 Day-Ahead Operations Process Version: 0.0.0 Effective: 9/17/2010

5.3 Day-Ahead Operations Process

The Market-Based Operating Entities will use a day-ahead operations process to establish the Firm Flow Limit on Coordinated Flowgates. If the Market-Based Operating Entities utilize a day-ahead unit commitment, they will supplement the day-ahead unit commitment with a security constrained economic dispatch tool, which uses a network analysis model that mirrors the real-time model found within their state estimators. As such, the day-ahead unit commitment and its associated Security Constrained Economic Dispatch respects facility limits and forecasted system constraints. Facility limits of Coordinated Flowgates under the functional control of Market-Based Operating Entities and the allocations of all Reciprocal Coordinated Flowgates will be honored.

For Coordinated Flowgates, a Market-Based Operating Entity can only use one of the following two methods to establish Firm Flow Limit. A Market-Based Operating Entity must use either the day-ahead unit commitment and its associated Security Constrained Economic Dispatch, or a Market-Based Operating Entity's GTL and unused Firm Transmission Service impacts, up to the Flowgate Limit, on the Coordinated Flowgate. At any given time, an entity must use only one method for all Coordinated Flowgates and must give ninety days notice to all other Reciprocal Entities, if it decides to switch from one method to the other method. On a case by case basis, with agreement by all Reciprocal Entities the ninety-day notice period may be waived.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
Section 5.4 Real-Time Operations Process - Operating Entity Capabilities Version: 0.0.0

Effective: 9/17/2010

5.4 Real-time Operations Process – Operating Entity Capabilities

Operating Entities’ real-time EMS’s have very detailed state estimator and security analysis packages that are able to monitor both thermal and voltage contingencies every few minutes. State estimation models will be at least as detailed as the IDC model for all the Coordinated and Reciprocal Coordinated Flowgates. Additionally, Reciprocal Entities will be continually working to ensure the models used in their calculation of Market Flow are kept up to date.

The Market-Based Operating Entities’ state estimators and Unit Dispatch Systems (UDS) will utilize these real-time internal flows and generator outputs to calculate both the actual and projected hour ahead flows (i.e., total Market Flows, Non-Firm Market Flows, and Firm Market Flows) on the Coordinated Flowgates. Using real-time modeling, the Market-Based Operating Entity’s internal systems will be able to more reliably determine the impact on Flowgates created by dispatch than the NERC IDC. The reason for this difference in accuracy is that the IDC uses static SDX data that is not updated in real-time. In contrast to the SDX data, the Market-Based Operating Entity’s calculations of system flows will utilize each unit’s actual output, updated at least every 15 minutes on an established schedule.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
Section 5.5 Market-Based Operating Entity Real-time Actions Version: 0.0.0 Effective: 9/17/2010

5.5 Market-Based Operating Entity Real-time Actions

Market-Based Operating Entities will have the list of Coordinated Flowgates modeled as monitored facilities in its EMS. The Firm Flow Limits a Market-Based Operating Entity will use for these Flowgates will be the Firm Flow Limits determined by the Firm Market Flow calculations.

The Market-Based Operating Entity will upload the real-time and one-hour ahead projected Firm Market Flows (7-FN) and Non-Firm Market Flows (6-NN) on these Flowgates to the IDC every 15 minutes, as requested by the NERC IDCWG and OATI (note that under reciprocal operations, some of this 6-NN may be quantified as Priority 2-NH). Market Flows will be calculated, down to five percent and down to zero percent, and uploaded to the IDC. When the real-time actual flow exceeds the Flowgate limit and the Reliability Coordinator, who has responsibility for that Flowgate, has declared a TLR 3a or higher, the IDC will determine tag curtailments, Market Flow relief obligations and NNL relief obligations using a 5% tag impact, Market Flow impact and NNL impact threshold. The Market-Based Operating Entity will respond to the relief obligation by redispatching their system in a manner that is consistent with how non-market entities respond to their NNL relief obligations. Note the Market-Based Operating Entity and the non-market-entities may provide relief through either: (1) a reduction of flows on the Flowgate in the direction required, or (2) an increase of reverse flows on the Flowgate.

Market-Based Operating Entities will implement this redispatch by binding the Flowgate as a constraint in their Unit Dispatch System (UDS). UDS calculates the most economic solution while simultaneously ensuring that each of the bound constraints is resolved reliably. Additionally, the Market-Based Operating Entity will make any point-to-point transaction curtailments as specified by the NERC IDC.

The Reliability Coordinator calling the TLR will be able to see the relief provided on the Flowgate as the Market-Based Operating Entity continues to upload its contributions to the real-time flows on this Flowgate.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
Section 6 - Reciprocal Operations

Reciprocal Coordination Agreements can be executed on a market-to-market basis, a market-to-non-market basis, and a non-market-to-non-market basis. While the congestion management portions of this document are intended to apply specifically to Market-Based Operating Entities, the agreement to allocate Flowgate capability is not dependent on an entity operating a centralized energy market. Rather, it simply requires that a set of Flowgates be defined upon which coordination shall occur and an agreement to perform such coordination.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
6.1 Reciprocal Coordinated Flowgates

In order to coordinate congestion management on a proactive basis, Operating Entities may agree to respect each other’s Flowgate limitations during the determination of AFC/ATC and the calculation of firmness during real-time operations. Entities agreeing to coordinate this future-looking management of Flowgate capacity are Reciprocal Entities. The Flowgates used in that process are Reciprocal Coordinated Flowgates.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
Section 6.2 The Relationship Between Coordinated Flowgates and Reciprocal Coordination

Coordinated Flowgates are associated with a specific entity’s operational sphere of influence. Reciprocal Coordination Flowgates are associated with the implementation of a Reciprocal Coordination Agreement between two Reciprocal Entities. By virtue of having executed such an agreement, a Flowgate Allocation can occur between these two Reciprocal Entities as well as all other Reciprocal Entities that have executed Reciprocal Coordination Agreements with at least one of these two Reciprocal Entities. When considering an implementation between two Reciprocal Entities, it is generally expected that each of the Reciprocal Coordinated Flowgates will meet the following three criteria:

- It will meet the criteria for Coordinated Flowgate status for both the Reciprocal Entities,
- It will be under the functional control of one of the two Reciprocal Entities and
- Both Reciprocal Entities have executed Reciprocal Coordination Agreements either with each other or with a third party Reciprocal Entity.
As shown in the illustration above, Operating Entity A, Operating Entity B and Operating Entity C each have their own set of Coordinated Flowgates (represented by the blue, yellow and red dotted-line circles). Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A’s, Operating Entity B’s or Operating Entity C’s service territory (the gray area), they will be considered Reciprocal Coordinated Flowgates between all three entities. Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A’s or Operating Entity B’s service territory (the purple area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity B and Operating Entity A only. Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity B’s or Operating Entity C’s service territory (the green area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity B and Operating Entity C only. Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A’s or Operating Entity C’s service territory (the orange area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity A and Operating Entity C only.

To the extent that entities other than Market-Based Operating Entities may enter into a Reciprocal Coordination Agreements, they may offer to coordinate on Flowgates that are Coordinated Flowgates (i.e., have passed one of the four tests defined within this document or otherwise been deemed to be a Coordinated Flowgate).

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
Section 6.3 Coordination Process for Reciprocal Flowgates Version: 0.0.0 Effective: 9/17/2010

6.3 Coordination Process for Reciprocal Flowgates

The following process and timing will be used for coordinating the ATC/AFC calculations and Firm Flow Limit calculations/Allocations between Reciprocal Entities. Further, the process quantifies and limits Priority 6 – NN service on the Reciprocal Coordinated Flowgates, as well as determines priority 2-NH service. All Reciprocal Entities’ Firm Flow Limits will be calculated on the same basis.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
Section 6.4 Calculating Historic Firm Flows Version: 0.0.0 Effective: 9/17/2010

6.4 Calculating Historic Firm Flows

As a starting point for identifying Allocations, an understanding must be developed of what Firm Flows would be in the historic Control Area structure. In other words, there must be a quantification of the Firm Flows that would have occurred if all Control Areas maintained their current configuration and continued to: (1) serve their native load with their Designated Network Resources, and (2) import and export energy at historical levels (based upon Firm Transmission Service reservations as of the Freeze Date, which is currently set as April 1, 2004. This flow is referred to as Historic Firm Flow.

“Historic Firm” Calculation Illustration

\[ \text{GtL} = \text{Designated Network Resources to Network Customers Delivery} \]


Reciprocal Entities will utilize the IDC Base Case model, or a mutually agreed upon alternative model as the reference base case for these calculations.

Effective Date: 9/17/2010 - Docket #: ER13-1158-000
Section 6.5 Recalculation of Initial Historic Firm Flow Values and Rates Version: 0.0.0

Effective: 6/16/2011

6.5 Recalculation of Initial Historic Firm Flow Values and Ratios

The Firm Transmission Service and Designated Network Resource to customer load defined by the Historic Firm Flow calculation will be updated in the recalculation of Historic Firm Flow utilizing any new Designated Network Resources, updated customer loads, and new transmission facilities. The original historic Control Areas will be retained for the recalculation of Historic Firm Flow. New Designated Network Resources will be included in the recalculation to the extent these new Designated Network Resources have been arranged for the exclusive use of load within the historic Control Areas and to the extent the total impact of all Designated Network Resources does not exceed the historic Control Area impact of Designated Network Resources as of a “Freeze Date” (defined as April 1, 2004). Any changes to Designated Network Resources and/or the transmission system that increase transmission capability will be assessed in accordance with the Reciprocal Entities AFC Coordination procedures prior to the increasing of Historic Firm Flow related to those systems.

The initial Historic Firm Flow calculated values and resulting Allocation ratios will be recalculated as seasonal cases are produced. This recalculation will utilize the same Firm Transmission Service reservations that were used in the initial Historic Firm Flow calculation. The same Firm Transmission Service reservations are used so that Market-Based Operating Entities that have their Firm Transmission Service internalized, grant fewer internal Firm Transmission Service reservations, or have their original Firm Transmission Service reservations end, because of their market operations, will retain at least the same level of Firm Transmission Service as in the initial Historic Firm Flow calculation. Therefore, the Firm Transmission Service component of the Historic Firm Flow will be frozen on the “Freeze Date” at the initially calculated level for both market and non-market entities.

Any new Control Areas that are added to the Firm Flow calculation process for any Reciprocal Entity, or another Operating Entity, will use Firm Transmission Service reservations from the initial Historic Firm Flow calculation date to establish their Firm Transmission Service component of the Historic Firm Flow.

As the recalculation for Historic Firm Flow is made for each time period, the higher of allocation value will be retained between the initial Historic Firm Flow calculation and the recalculation (See “Forward Coordination Process” Section 6.6, step 8.f). To the extent an Operating Entity has made commitments based on the higher of Allocation value, a recalculation does not reduce previously calculated Allocations.

When a Flowgate experiences a transitory limit reduction or de-rating, there will be no change made to the historic allocations. In effect, the Operating Entity responsible for the Flowgate is expected to absorb the impact of the de-rating by not reducing the historic allocation of the other Operating Entities. This practice is consistent with the use of the higher-of logic in the historic allocation process. Where a change in system conditions, such as a significant transmission outage, affects flows on a longer term basis the Reciprocal Entities will discuss whether historic
allocations, including an over-ride of the higher-of logic, should be rerun to recognize the effects of the change in system conditions in the historic allocations. The historic allocations shall be rerun only if the affected Reciprocal Entities mutually agree.

Effective Date: 6/16/2011 - Docket #: ER13-1158-000
6.6 Forward Coordination Processes

1. For each Reciprocal Coordinated Flowgate, a managing entity and an owning entity will be defined. The manager will be responsible for all calculations regarding that Flowgate; the owner will define the set of Firm Transmission Service reservations to be utilized when determining Firm Transmission Service impacts on that Flowgate.

2. Managing entities will calculate both Historic Firm Gen-to-Load Flow impacts and historic Firm Transmission Service impacts for all entities. These impacts will be used to define the Historic Ratio and the Allocation of transmission capability.

3. The managing entity will utilize the current NERC IDC Base Case (or other mutually agreeable base case) to determine impacts. The case should be updated with the most current set of outage data for the time period being calculated.

4. Managing entities will calculate Allocations on the following schedule:

<table>
<thead>
<tr>
<th>Allocation Run Type</th>
<th>Allocation Process Start</th>
<th>Range Allocated</th>
<th>Allocation Process Complete</th>
</tr>
</thead>
<tbody>
<tr>
<td>April Seasonal Firm</td>
<td>Every April 1 at 8:00 EST</td>
<td>Twelve monthly values from October 1 of the current year through September 30 of the next year</td>
<td>April 1 at 12:00 EST</td>
</tr>
<tr>
<td>October Seasonal Firm</td>
<td>Every October 1 at 8:00 EST</td>
<td>Twelve monthly values from April 1 of next year through March 31 of the following year</td>
<td>October 1 at 12:00 EST</td>
</tr>
<tr>
<td>Monthly Firm</td>
<td>Every month on the second day of the month at 8:00 EST</td>
<td>Six monthly values for the next six successive months</td>
<td>2nd of the month at 12:00 EST</td>
</tr>
<tr>
<td>Weekly Firm</td>
<td>Every Monday at 8:00 EST</td>
<td>Seven daily values for the next Monday through Sunday</td>
<td>Monday at 12:00 EST</td>
</tr>
<tr>
<td>Two-Day Ahead Firm</td>
<td>Every Day at 17:00 EST</td>
<td>One daily value for the day after tomorrow</td>
<td>Current Day at 18:00 EST</td>
</tr>
<tr>
<td>Day Ahead Non-Firm</td>
<td>Every Day at 8:00 EST</td>
<td>Twenty-four hourly values for the next 24-hour period (Next Day HE1-HE24 EST)</td>
<td>Current Day at 9:00 EST</td>
</tr>
</tbody>
</table>

5. Historic Ratios are defined during the seasonal runs the first time an impact is calculated. For example, the 2004 April seasonal firm run would define the Historic Ratio for April 2005 – September 2005 (October through March would have been calculated during the 2003 October seasonal firm run). The Historic Ratio is based on the total impacts of the Reciprocal Entity on the Flowgate (Historic Firm Gen-to-Load Flows and historic Firm Transmission Service flows, down to 0%) relative to the total impacts of all other Reciprocal Entities’ impacts on the Flowgate. For example, if Reciprocal Entity A had a
30 MW impact on the Flowgate and Reciprocal Entity B had a 70 MW impact on the Flowgate, the Historic Ratios would be 30% and 70%, respectively.

6. The same rules defined in the “Market-Based Operating Entity Congestion Management” Section 5 of this document for use in determining Firm Transmission Service impacts (NNL) shall apply when performing Allocations.

7. Additional rules to be used when considering Firm Transmission Service impacts are defined later within this section.

8. For each firm Allocation run described above, the managing entity will take the following steps to determine Allocations down to 0% for each of the Flowgates, in both the forward and reverse direction, they are assigned to manage:
   a. Retrieve the Flowgate limit
   b. Subtract the current Transmission Reliability Margin (TRM) value (may be zero)
   c. Subtract the sum of all historically determined Firm Flow impacts for all entities based on impacts greater than or equal to 5%
   d. Accommodation of Capacity Benefit Margin (CBM)
      20 If no capacity remains after step (c), entities’ firm Allocation is limited to this amount (i.e., their Firm Flow impacts from impacts of 5% or greater), and the firm Allocation for the entity with functional control over the Flowgate is increased by the current CBM value (may be zero).
      21 If capacity does remain after step (c), and the sum of all Reciprocal Entities’ impacts below 5% plus CBM is less than the remaining capacity from step (c), that capacity is allocated to the Reciprocal Entities pro-rata based on their Firm Flow impacts due to impacts less than 5% up to the total amount of their Firm Flow impacts due to impacts less than 5%.
      22 If there is not sufficient capacity for all impacts below 5% plus CBM to be accommodated, the current CBM value is subtracted from the remaining capacity from step (c), and granted to the entity with functional control over the Flowgate. Any capacity remaining is allocated to the Reciprocal Entities pro-rata based on their Firm Flow impacts due to impacts less than 5%.
   e. Any remaining capacity, after step (d) will be considered firm and allocated to Reciprocal Entities based on their Historic Ratio (as described in step 5). If the remaining capacity allocated to the entity with functional control over the Flowgate meets or exceeds the current CBM value, no further effort is needed. If the remaining capacity is less than the CBM, capacity will first be reduced by the CBM, and the entity with functional control over the Flowgate will be granted the capacity needed to support the CBM. In addition each Reciprocal Entity (including the entity with functional control over the Flowgate) will receive allocations determined as a pro-rata share of the remaining capacity (as described in Step 5).
   f. Upon completion of the Allocation process, the managing entity will compare the current preliminary Allocation to the previous Allocations. For any given Flowgate, the larger of the Allocations will be considered the Allocation (i.e., an Allocation cannot decrease). Once all preliminary Allocations have been compared and the final Allocation determined, the managing entity will distribute the Allocations to the appropriate Reciprocal Entities. This Allocation will
consist of the firm Gen-to-Load limit and a portion of capability that can be used either for Firm Transmission Service or additional firm Gen-to-Load service.

9. For the non-firm Allocation run described above, the managing entity will take the following steps to determine Allocations down to 0% for each of the Flowgates, in both the forward and reverse direction, they are assigned to manage. For each hour, the managing entity shall:
   a. Retrieve the Flowgate limit
   b. Subtract the current TRM value (may be zero)
   c. Subtract the sum of all hourly historically determined Firm Flow impacts for all entities based on impacts greater than or equal to 5%
   d. Subtract the sum of all hourly historically-determined Firm Flow impacts for all Reciprocal Entities based on impacts less than 5%
   e. Any remaining capacity will be allocated to Reciprocal Entities based on their Historic Ratio (as described in step 5).
   f. The two-day ahead firm Allocation is subtracted from the total entity Allocation (from steps c, d, and e).

23 If the result is positive, this value will be equivalent to the Priority 6-NN Allocation/limit, and the Firm Flow Limit for 0% Market Flows will be the two-day ahead firm Allocation.

24 If the result is negative or zero, the Priority 6-NN Allocation will be calculated by subtracting the total entity Allocation (from steps c, d and e) from the two-day ahead firm Allocation. The Firm Flow Limit for 0% Market Flows will be the equivalent of the total entity allocation.

g. Upon completion of the Allocation process, the managing entity will distribute the Allocations to the appropriate Reciprocal Entities. These Allocations will be considered non-firm network service.

When a Market-Based Operating Entity is uploading Firm Market Flow contributions to the IDC, they will be responsible for ensuring that any firm Allocations are properly accounted for. If firm Allocations are used to provide additional firm network service, they should be included in the Firm Market Flow contribution. If they are used to provide additional Firm Transmission Service, they should not be included in the Firm Market Flow contribution.

The Market-Based Operating Entities will maintain in real-time their Firm Transmission Service and Network Non-Designated service impacts, including associated Market Flows, within their respective firm and Priority 6 total Allocations. The Firm Transmission Service impacts will be based on schedules. The Operating Entities participating in the Coordinated Process for Reciprocal Flowgates will respect their allocations when granting Firm Transmission Service.

Using the derived firm Allocation value, the Market-Based Operating Entity may choose to enter this value as a Flowgate limit for the respective Flowgate. If entered as a Flowgate limit, the Day-Ahead unit commitment will not permit flows to exceed this value as it selects units for this commitment. Market-Based Operating Entities will use the Flowgate limit to restrict unit outage scheduling for a Coordinated Flowgate when maintenance outage coordination indicates possible congestion and there is recent TLR activity on a Flowgate.
As Reciprocal Entities gain more experience in this process, implement and enhance their systems to perform the Firm Flow calculations and Allocations, they may change the timing requirements for the Forward Coordination Process by mutual agreement.

### 6.6.1 Determining Firm Transmission Service Impacts

Firm impacts used in the Allocation process incorporate the Firm Transmission Service flows. Similar to the network service calculation described previously, to calculate each Firm Transmission Service transaction’s impact on the Flowgate, the following process is utilized:

1. Utilize a base case to determine the Generation Shift Factor for the source Control Area with respect to a specific Flowgate.
   
   (b) Utilize the same base case to determine the Generation Shift Factor for the sink Control Area with respect to that Flowgate.
   
   (c) Utilize superposition to calculate the TDF for that source to sink pair with respect to that Flowgate.
   
   (d) Multiply the transactions energy transfer by the TDF to determine that transactions flow on the Flowgate.

Summing each of these impacts by direction will provide the directional Firm Transmission Service impact on the Flowgate.

Combining the directional Firm Transmission Service impacts with the directional NNL impacts will provide the directional Firm Flows on the Flowgate.

### 6.6.2 Rules for Considering Firm Transmission Service

1. Firm Transmission Service and Designated Network Resources that have an OASIS reservation are included in the calculation.

2. Reciprocal Entities will utilize a Freeze Date of April 1, 2004. Reciprocal Entities will utilize a reference year of June 1, 2004 through May 31, 2005 for determining the confirmed set of reservations that will be used in the Allocation process. The reference year is used such that reservation impacts in a given month in the reference year are used for each comparable month going forward in the Allocation process. For example, the Allocations for July 2004, July 2005, and July 2006 etc. will always use the July 2004 reservation impacts from the reference year. Confirmed reservations received after the Freeze Date will not be considered.

3. A potential for duplicate reservations exists if a transaction was made on individual CA tariffs (not a regional tariff) and both parties to the transaction (source and sink) are Reciprocal Entities. In this case, each Reciprocal Entity will receive 50% of the transaction impact.

4. To the extent a partial path reservation is known to exist, it will have 100% of its impacts considered on Reciprocal Coordinated Flowgates owned by the party that sold the partial
path service, split 50/50 between the Source Reciprocal Entity and the Sink Reciprocal Entity, and 0% of its impacts considered on other Reciprocal Coordinated Flowgates.

5. Because reservations that are totally within the footprint of the regional tariff do not have duplicate reservations, these reservations will have the full impact considered even though both parties to the transaction (source and sink) are within the boundaries of the regional tariff and will be considered Reciprocal Entities, split 50/50 between the Source Reciprocal Entity and the Sink Reciprocal Entity, which in this case are the same. Similar to the firm network service calculation, the Firm Transmission Service calculation:
   a. Will consider all reservations (including those with less than 5% impact)
   b. Will base response factors on the topology of the system for the period under consideration
   c. In general, will not make a generation-to-load calculation where a reservation exists.

6.6.3 Limiting Firm Transmission Service

The Flowgate Allocations down to 0% will represent the share of total flowgate capacity (STFC) that a particular entity has been allocated. This STFC represents the maximum total impact that entity is allowed to have on that Flowgate.

In order to coordinate with the existing AFC process, it is necessary that this number be converted to an available STFC (ASTFC) which represents how much Flowgate capability remains available on that Flowgate for use as Transmission Service. In order to accomplish this, the entity receiving STFC will do the following:

<table>
<thead>
<tr>
<th>Step</th>
<th>Example</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.) Start with the STFC</td>
<td>100</td>
</tr>
<tr>
<td>2.) Add all forward Gen to Load impacts (down to 0%) and all Reverse Gen to Load impacts (down to 0%) to obtain the Net Gen to Load impacts. The Gen to Load impacts should be based on the best estimate of firm Gen-to-Load Flow for the time period being evaluated.</td>
<td>42 + (-20) = 22</td>
</tr>
<tr>
<td>3.) Subtract the net Gen to Load impacts from the STFC</td>
<td>100 – 22 = 78</td>
</tr>
<tr>
<td>4.) Subtract the CBM to produce an interim STFC</td>
<td>78 – 0 = 78</td>
</tr>
<tr>
<td>5.) Determine the Transmission Service impacts of service that has been sold. By default, it should be assumed that 100% of forward service and 15% of counterflowing</td>
<td>58 + (0.15 (-45)) = 58 + (-6.75) ≈</td>
</tr>
</tbody>
</table>

58 + (-7) = 51 |
service will be scheduled and used. However, if Flowgate “owner” uses different percentages in their AFC calculation and the Flowgate manager’s calculation engine support it, percentages other than 100% and 15% may be used. Add all forward Transmission Service impacts (down to 0%) and all appropriate reverse Transmission Service impacts (down to 0%) to obtain the weighted net Transmission Service impacts. The Transmission Service impacts should be based on the current set of reservations in effect for the time period being evaluated (not the historic reservation set).

6.) Subtract the weighted net Transmission Service impacts from the Interim STFC. The result is the ASTFC.

6.) Subtract the weighted net Transmission Service impacts from the Interim STFC. The result is the ASTFC.

\[78 - 51 = 27\]

The ASTFC values for Reciprocal Coordinated Flowgates will be posted on OASIS along with the Allocation results. This ASTFC can then be compared with the AFC calculated through traditional means when evaluating firm requests made on OASIS.

If the AFC value is LOWER than the ASTFC value, the AFC value should be utilized for the purpose of approving/denying service. In this case, while the Allocation process might indicate that the entity has rights to a particular Flowgate through the Allocation process, current conditions on that Flowgate indicate that selling those rights would result in overselling of the Flowgate, introducing a reliability problem.

If the AFC value is HIGHER than the ASTFC value, the ASTFC value should be utilized for the purpose of approving/denying service. In this case, while the AFC process might indicate that the entity can sell more service than the Allocation might indicate, the entity is bound to not sell beyond their Allocation.

If a Reciprocal Entity uses all of its firm Allocation and desires to obtain additional capacity from another Reciprocal Entity who has remaining capacity, that additional capacity may be obtained using the procedures documented below.

**Effective Date: 12/1/2011 - Docket #: ER13-1158-000**
Section 6.7 Sharing or Transferring Unused Allocations Version: 0.0.0 Effective: 9/17/2010

6.7 Sharing or Transferring Unused Allocations

Reciprocal Entities shall use the following process for the sharing or transferring of unused Allocations down to 0% between each other.

6.7.1 General Principles

This process includes the following general principles in the treatment of unused Allocations:

1. A desire to fully utilize the Reciprocal Entities’ Allocations such that in real-time, an unused Allocation by Reciprocal Entities is caused by a lack of commercial need for the Allocation by Reciprocal Entities and not by restrictions on the use of the Allocation.

2. For short-term requests (less than one year) where the lack of an Allocation could otherwise result in the denial of Transmission Service requests, there should be a mechanism to share or acquire a remaining Allocation on a non-permanent basis for the duration of the short-term transmission service requests. The short-term Allocation transfers would revert back to the Reciprocal Entity with the original Allocation after the short term request expires.

3. For long-term requests (one year or longer) where the lack of an Allocation could otherwise cause the construction of new facilities, there should be a mechanism to acquire a remaining Allocation such that new facilities are built only because they are needed by the system to support the transaction and not because of the Allocation split between Reciprocal Entities. Long-term Allocation transfers would apply to the original time period of the request including any roll-over rights that are granted for such requests.

4. Due to limitations on the frequency of transferring updated Allocation values and AFC’s between the Reciprocal Entities, the Reciprocal Entities will utilize buffers to reduce the risk of overselling the same service, and to set aside a portion of the unused Allocation for the owner of the unused Allocation to accommodate any request that they may receive. The buffer will be reduced on a Flowgate based upon factors such as the rating of the Flowgate and operational experience, with the goal to maximize the use of the unused Allocation. The rationale for reducing the buffer is that potentially significant amounts of Transmission Service (up to many times the buffer amount) may be denied otherwise by the non-owner of the unused Allocation.

6.7.2 Provisions for Sharing or Transferring of Unused Allocations:
a. Based upon the proposed infrastructure for Allocation calculations, daily Allocations are available for 7 days into the future and Weekly and Monthly Allocations are available up to 18 months into the future. Sharing and transferring of unused Allocations will be limited to the granularity of the Allocation calculations.

b. The Reciprocal Entities will share or transfer their unused firm Allocations during the time periods up until day ahead with the goal to fully utilize the Allocations.

c. This sharing or transfer of the unused Allocation will occur automatically for short-term Transmission Service requests, and manually for long-term (one year or greater) Transmission Service requests. The Reciprocal Entity that has been requested to transfer unused Allocations to the other Reciprocal Entity for a long-term request shall respond within 5 business days of receipt of the transfer request.

d. The Reciprocal Entities will post information available to the other Reciprocal Entity on all requests granted that shared or acquired the other Reciprocal Entity’s Allocation on a daily basis for review.

e. Sharing an Unused Allocation During the Near-Term

   . The Reciprocal Entities will share their Allocations during the near-term (the first 7 days up until day ahead or a mutually agreed upon timeframe) with the goal to fully utilize the Allocations once in real-time through an automated process.

   a. This sharing of the unused Allocation during the near-term will occur such that an unused Allocation that has not already been committed for use by either Firm Transmission Service or for market service will be made available to the other Reciprocal Entities for their use to accommodate Firm Transmission Service requests submitted on OASIS.

   b. Other firm uses of the transmission system involving generation to load deliveries, which are not evaluated via automated request evaluation tools, will be handled via off-line processes. The core principles to be applied in such cases include:

      a. A sharing of Allocation can occur.
      b. The sharing shall be done on a comparable basis for the market and non-market entities.
      c. The sharing is not related to projected Market Flow absent new DNRs or Transmission Service submitted on OASIS.

   4. The details of the process will include such items as which DNRs are covered, time-lines for designations and comparable evaluation of DNRs. If the details of this process can not be agreed upon, there shall be no sharing of the unused Allocations during the near-term.

   c. A buffer will limit the amount of Allocation that can be shared for short-term requests during automated processing of the Allocation sharing process. The owner of the unused Allocation is not restricted by the buffer. The buffer is defined as a percentage of the last updated unused Allocation, provided that the
buffer shall not be allowed to be less than a certain MW value. For example, a 25% or 20 MW buffer would mean that the requesting entity can use the other Reciprocal Entity’s unused Allocation while making sure that the other entity’s unused Allocation does not become smaller than 25% of the reported unused amount or 20 MW. The specific provisions of the buffer shall be mutually agreed to by the Reciprocal Entities prior to implementing a sharing of unused Allocation. The buffer will not be used in manual processing of Allocation sharing requests. For manual processing of requests, the owner of the unused Allocation will share the remaining unused Allocation to the extent they do not need the unused Allocation for pending Transmission Service requests.

d. For the sharing of unused Allocations in the near-term, the Allocations are not changed and should congestion occur the NERC IDC obligations for the giving Reciprocal Entity will be in accordance with its original Allocation. The receiving Reciprocal Entity will not be required to retract or annul any service previously granted due to the sharing of Allocations.

f. Acquiring an Unused Allocation Beyond the Near Term

. When a Reciprocal Entity does not have sufficient Allocation on a Flowgate to approve a firm point-to-point or network service request made on OASIS and evaluated via automated request evaluation tools and the other Reciprocal Entity has a remaining Allocation, the deficient Reciprocal Entity will be able to acquire an Allocation from the Reciprocal Entity with the remaining Allocation. This Allocation must not already be committed for other appropriate uses, as agreed to by the Reciprocal Entities, and sufficient AFC must remain on the Flowgate, or will be created, to accommodate the request. Such cases will be handled via automated processes.

a. Other firm uses of the transmission system involving generation to load deliveries, which are not evaluated via automated request evaluation tools, will be handled via off-line processes. The core principles to be applied in such cases include:

b. a. A transfer of Allocation can occur.

b. The transfer shall be done on a comparable basis for the market and non-market entities.

c. The transfer is not related to projected market flow absent new DNRs or Firm Transmission Service submitted on OASIS.

d. The details of the process will include such items as which DNRs are covered, time-lines for designations and comparable evaluation of DNRs. If the details of this process can not be agreed upon, there shall be no transfer of the Allocation for the time period beyond the near term.

c. A buffer will limit the amount of Allocation that can be acquired for these requests during automated processing of the Allocation transfer process. The owner of the unused Allocation is not restricted by the buffer. The buffer is defined as a percentage of the last updated unused Allocation, provided that the buffer shall not be allowed to be less than a certain MW value. For example, a
25% or 20 MW buffer would mean that the requesting entity can use the other Reciprocal Entity’s unused Allocation while making sure that the other entity’s unused Allocation does not become smaller than 25% of the reported unused amount or 20 MW. The specifics of the buffer shall be mutually agreed to by the Reciprocal Entities prior to implementing a transferring of unused Allocation. The buffer will not be used in manual processing of Allocation sharing requests. For manual processing of requests, the owner of the unused Allocation will transfer the remaining unused Allocation to the extent they do not need the unused Allocation for pending Transmission Service requests.

d. The determination of whether the remaining Allocation has already been committed will be established based on OASIS queue time. All requests received prior to the queue time will be considered prior commitments to the remaining Allocation, while such requests are in a pending state (e.g. study status) or confirmed state. Requests received after the queue time will be ignored when determining whether remaining capacity has already been committed.

e. In the event that prior-queued requests are still in a pending state (i.e. not yet confirmed), the Reciprocal Entity requesting a transfer of unused Allocations may await the resolution of any prior-queued requests in the other Reciprocal Entity’s OASIS queue before relinquishing its ability to request an Allocation transfer.

f. For the transfer of unused Allocations, the Reciprocal Entity’s Allocations will be changed to reflect the Allocation transfer at the time the Allocation transfer request is processed. To the extent the request is not ultimately confirmed, the Allocation will revert back to the original Reciprocal Entity with the remaining Allocation. For yearly requests, the transfer of the Allocation applies to the original time period of the request including any roll-overs that are granted.

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Section 6.8 Market-Based Operating Entities Quantify and Provide Data for Market Flow

In addition to the responsibilities described earlier in “Market-Based Operating Entity Congestion Management” Section 5 of this document, Market-Based Operating Entities will have an additional obligation, on Reciprocal Coordinated Flowgates, to further quantify their Non-Firm Flows into two (2) separate priorities: Non-Firm Network (6-NN), and Non-Firm Hourly (2-NH). Priorities will be determined as follows:

1. If the Market Flow exceeds the sum of the Firm Flow Limit and the 6-NN Allocation, then:
   - 2-NH = Market flow – (Firm Flow Limit + 6-NN Allocation)
   - 6-NN = 6-NN Allocation
   - 7-FN = Firm Flow Limit

2. If the Market Flow exceeds the Firm Flow Limit but is less than the 6-NN Allocation, then:
   - 2-NH = 0
   - 6-NN = Market Flow – Firm Flow Limit
   - 7-FN = Firm Flow Limit

3. If the Market Flow does not exceed the Firm Flow Limit, then
   - 2-NH = 0
   - 6-NN = 0
   - 7-FN = Market Flow

All other aspects of this data remain identical to those described in “Market-Based Operating Entity Congestion Management” Section 5.

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Section 6.9 Real-time Operations Process for Market-Based Operating Entities

Version: 0.0.0 Effective: 9/17/2010

6.9 Real-time Operations Process for Market-Based Operating Entities

6.9.1 Market-Based Operating Entity Capabilities

Capabilities remain as described in “Market-Based Operating Entity Congestion Management” Section 5.

6.9.2 Market-Based Operating Entity Real-time Actions

Procedures remain as described in “Market-Based Operating Entity Congestion Management” Section 5. However, as described above, additional information regarding the firmness of those Non-Firm Market Flows will be communicated as well. A portion will be reported as 6-NN, while the remainder will be reported as 2-NH. This will provide additional ability for the IDC to curtail portions of the Non-Firm Market Flows earlier in the TLR process.

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Appendix A Glossary Version: 0.0.0 Effective: 9/17/2010

Appendix A – Glossary

**Allocation** – A calculated share of capability on a Reciprocal Coordinated Flowgate to be used by Reciprocal Entities when coordinating AFC, transmission sales, and dispatch of generation resources.

**Available Flowgate Capability (AFC)** – the applicable rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

**AFC Flowgate** – A Flowgate for which an entity calculates AFC’s.

**Control Area** – Shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied.

**Control Zones** – Within an Operating Entity Control Area that is operating with a common economic dispatch, the Operating Entity footprint is divided into Control Zones to provide specific zonal regulation and operating reserve requirements in order to facilitate reliability and overall load balancing. The zones must be bounded by adequate telemetry to balance generation and load within the zone utilizing automatic generation control.

**Coordinated Flowgate (CF)** – shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of this document. For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion Management portion of this document (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a Third Party.

**Designated Network Resource** – A resource that has been identified as a designated network resource pursuant to a transmission provider’s Open Access Transmission Tariff.

**Firm Flow** – The estimated impacts of Firm Transmission Service on a particular Coordinated or Reciprocal Coordinated Flowgate.

**Firm Flow Limit** – The maximum value of Firm Flows an entity can have on a Coordinated or Reciprocal Coordinated Flowgate, based on procedures defined in Sections 4 and 5 of this document.

**Firm Market Flow** – The portion of Market Flow on a Coordinated or Reciprocal Coordinated Flowgate related to contributions from the native load serving aspects of the dispatch (constrained as appropriate by the Firm Flow Limit).
**Firm Transmission Service** – The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption or similar quality service offered by transmission providers by contract that do not require the filing of a rate schedule. Firm Transmission Service only includes firm point-to-point service, network designated transmission service and grandfather agreements deemed firm by the transmission provider as posted on OASIS.

**Flowgate** – A representative modeling of facilities or groups of facilities that may act as significant constraint points on the regional system.

**Freeze Date** – the cutoff date chosen by Reciprocal Entities to be used in the calculation of Historic Firm Flows.

**Gen to Load (GTL)** – See Network and Native Load.

**Generator Shift Factor** – A factor to be applied to a generator’s expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate, referenced to a swing bus.

**Historic Firm Flow** – The estimated total impact an entity has on a Reciprocal Coordinated Flowgate when considering the impacts of (1) its historic Designated Network Resources serving native load, and (2) imports and exports, based on Firm Transmission Service reservations that meet the “Freeze Date” criteria.

**Historic Firm Gen-to-Load Flow** – The flow associated with the native load serving aspects of dispatch that would have occurred if all Control Areas maintained their current configuration and continued to serve their native load with their generation.

**Historic Ratio** – The ratio of Historic Firm Flow of one Reciprocal Entity compared to the Historic Firm Flow of all Reciprocal Entities on a specific Reciprocal Coordinated Flowgate.

**LMP Based System or Market** – An LMP based system or market utilizes a physical, flow-based pricing system to price internal energy purchases and sales.

**Load Shift Factor** – A factor to be applied to a load’s expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or Flowgate, referenced to a swing bus.

**Locational Marginal Pricing (LMP)** – the processes related to the determination of the LMP, which is the market clearing price for energy at a given location in a Market-Based Operating Entity’s market area.

**Market Flows** – The calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity’s market.

**Market-Based Operating Entity** – An Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.
**Network and Native Load (NNL)** – the impact of generation resources serving internal system load, based on generation the network customer designates for Network Integration Transmission Service (NITS). NNL is also referred to as Gen to Load.

**Non-Firm Market Flow** – That portion of Market Flow related to a Market-Based Operating Entity’s market operations in excess of that entity’s Firm Market Flow.

**Operating Entity** – An entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

**Reciprocal Coordination Agreement** – An agreement between Operating Entities to implement the reciprocal coordination procedures defined in the CMP.

**Reciprocal Coordinated Flowgate (RCF)** – A Flowgate that is subject to reciprocal coordination by Operating Entities, under either this Agreement (with respect to Parties only) or a Reciprocal Coordination Agreement between one or more Parties and one or more Third Party Operating Entities. An RCF is:

1. A CF that is (a) (i) within the operational control of Reciprocal Entity or (ii) may be subject to the supervision of Reciprocal Entity as Reliability Coordinator, and (b) affected by the transmission of energy by two or more Parties; or
2. A CF that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to CMP reciprocal coordination procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or
3. A CF that is designated by agreement of both Parties as an RCF.

**Reciprocal Entity** – an entity that coordinates the future-looking management of Flowgate capacity in accordance with a Reciprocal Coordination Agreement as developed under Section 6 of this document, or a congestion management process approved by the Federal Energy Regulatory Commission; provided such congestion management process is identical or substantially similar to this Congestion Management Process.

**Security Constrained Economic Dispatch** – the utilization of the least cost economic dispatch of generating and demand resources while recognizing and solving transmission constraints over a single Market-Based Operating Entity Market.

**Transfer Distribution Factor** – the portion of an interchange transaction, typically expressed in per unit, that flows across a Flowgate.

**Transmission Service** – services provided to the transmission customer by the transmission service provider to move energy from a point of receipt to a point of delivery.
Appendix B - Determination of Marginal Zone Participation Factors

In order for the IDC to properly account for tagged transactions, a Market-Based Operating Entity will need to send data describing the locations of the marginal generators that are either supplying generation to exports or are having energy replaced by imports.

In general, the Market-Based Operating Entity will be required to define a set of zones that can each be easily aggregated into a common distribution factor that is representative of the zone. This information must be shared and coordinated with the interchange distribution calculator. Following this step, the Market-Based Operating Entity must then send to the IDC participation factors for those zones (percentages that indicate on a real-time basis how those zones are providing or would provide marginal megawatts). Data sets for each external source/sink are required, which correspond to:

- j. An IMPORT set, which indicates the next marginal units to supply replacement energy should the import transactions be curtailed, and
- k. An EXPORT set, which indicates the last marginal units used to supply the energy exported to other areas.

Marginal Zone Definition

Marginal Zones will be determined through collaboration of the Market-Based Operating Entity with the relevant NERC and/or NAESB working group. As stated above, Marginal Zones should be comprised of generators that have electrically similar characteristics from a distribution factor point-of-view.

Participation Factor Calculation

Raw Marginal Zone Participation Factors are determined relatively simply. The Market-Based Operating Entity will examine the constraints and pricing information for the entire market footprint and determine the percentages of generation output in each zone that represents the marginal megawatts that the zones are providing or would be providing. These will establish, for imports and exports, a set of participation factors that, when summed, will equal 100%.
Appendix C - Flowgate Determination Process

This section is has been added to clarify:

- How initial Flowgates are identified (Figure C-1, Table C-1)
  - Process for Flowgates in the Coordinated Flowgate list
  - Process for Flowgates in the Reciprocal Coordinated Flowgate list
  - Process for Flowgates in the AFC List
- How Flowgates will be added (Figure C-2, Table C-2)
- How often Flowgates are changed (Figure C-2, Table C-2)
Figure C-1
Determine AFC Flowgates, Coordinated Flowgates, and Reciprocal Coordinated Flowgates

1) Retrieve FG From List of Known FG's
2) Does FG Pass >=1 CMP Study?
   YES
   3) Is there a mutually agreed upon reason this should not be a CF?
      NO
      10) Is there a unilaterally agreed upon reason this should be a CF?
          YES
          4) Is Flowgate under control of RE?
             NO
             5) Is Flowgate an AFC Flowgate?
                YES
                6) Set FG = Coordinated
                   YES
                   7) Is FG Coordinated for >=2 Reciprocal Entities and owned by a Reciprocal Entity?
                      NO
                      8) Set FG = RCF
                         YES
                         11) Is this a mutually agreed upon RCF?
                            NO
                            9) Are there more FG's on the list?
                               NO
<table>
<thead>
<tr>
<th>Step</th>
<th>Activity</th>
<th>Requirements</th>
<th>Detailed Description</th>
<th>Additional Documentation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Retrieve FG From List Of Known FG’s</td>
<td>Retrieve FG from AFC list of FGs, NERC Book of FGs, and any other list of FGs.</td>
<td>• Retrieve the FG from the list of FGs. If a Reciprocal Entity wants us to consider a temporary FG it would go through the same process.</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Determine if FG passes &gt;= 1 CMP Study</td>
<td></td>
<td>• If the FG passes any of the studies, determine if there is mutually agreed upon reason why this should not be a coordinated FG. • If the FG does not pass any of the studies, it will be determined if there is a unilaterally decided reason for inclusion as a CF. Section 2 b. See Impacted Flowgate Determination - Section 3</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Is There a Mutually Agreed Upon Reason This Should Not Be A Coordinated Flowgate</td>
<td></td>
<td>• If there is no mutually agreed reason why this FG should not be considered coordinated, test whether FG is under control of a Reciprocal Entity. • If there is a mutually agreed reason why this FG should not be considered coordinated, record the reason proceed to Step 9.</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Is the Flowgate under control of a Reciprocal Entity</td>
<td>If the flowgate is under the control of a non-reciprocal entity and the Flowgate passes one of the four tests it will be treated as a coordinated Flowgate.</td>
<td>• If the Flowgate is not under control of a Reciprocal Entity proceed to Step 6. • If the Flowgate is under control of a Reciprocal Entity Proceed to Step 5.</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Is Flowgate an AFC Flowgate</td>
<td>A check is done to determine if the Flowgate controlled by a Reciprocal Entity is in its AFC process. If it is not the Flowgate will not be treated as a Coordinated Flowgate.</td>
<td>• If the Flowgate is in the AFC process proceed to Step 6. • Otherwise proceed to Step 9</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Set FG = Coordinated</td>
<td>The FG would be coordinated for the entity.</td>
<td>• The FG would be considered a CF.</td>
<td></td>
</tr>
<tr>
<td>Step</td>
<td>Activity</td>
<td>Requirements</td>
<td>Detailed Description</td>
<td>Additional Documentation</td>
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</tbody>
</table>
| 7    | Is FG Coordinated for >= 2 Reciprocal Entities and “owned” by a Reciprocal Entity | Determine whether the FG is coordinated for two or more Reciprocal Entities | - If the FG is coordinated for two or more Reciprocal Entities and it is “owned” by one of the entities, it will be added to the CMP process as a reciprocal coordinated FG.  
- If it is not coordinated for two or more Reciprocal Entities and “owned” by one of the entities, determine if it is a mutually agreed upon RCF. | CM Process - Section 6 |
| 8    | Set FG = RCF | Set the Flowgate equal to a Reciprocal Coordinated Flowgate. | - Set the Flowgate equal to a Reciprocal Coordinated Flowgate.  
- Proceed to Step 9. | |
| 9    | Are there more FGs on the list? | Determine if there are any more FGs on the list that need to go through the CMP determination process. | - If there are no more FGs that need to go through the determination process, the process ends.  
- If there are more FGs that need to go through the determination process, retrieve the next one.  
- Proceed to Step 1 if another FG requires evaluation.  
- Otherwise, the process ends. | |
| 10   | Is There a Unilateral Decision This Should Be A Coordinated FG | This decision determines if an entity wants to make this a Coordinated FG for a reason other than the four tests. | - If an entity decides to make this a coordinated FG, proceed to Step 4.  
- Otherwise, proceed to Step 9. | |
| 11   | Is This a Mutually Agreed Upon RCF | Determine if there is a mutually agreed reason this should be considered a Reciprocal Coordinated Flowgate. | - If there is no mutually agreed reason this should be considered an RCF, leave it as coordinated and check for more FGs.  
- If there is a mutually agreed reason this should be considered an RCF, mark it as such.  
- If Reciprocal Entities decide to make the Flowgate Reciprocal proceed to Step 8.  
- Otherwise, proceed to Step 9. | |
Figure C-2
Flowgate Review and Customer Flowgate Request

1) Bi-Annual Review of IDC BOF & AFC Flowgates
2) Monthly Update Of Book of FG's and Data Exchange
3) Customer Flowgate request
4) Temporary Flowgate added by Reciprocal Entity

5) Run through Flowgate process & tests

6) AFC / CF / RCF Flowgate List
<table>
<thead>
<tr>
<th>Steps</th>
<th>Activity</th>
<th>Requirements</th>
<th>Detailed Description</th>
<th>Additional Documentation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Bi-Annual Review of the BOFs and AFC FGs</td>
<td>Retrieve the FG from the list of FGs for the entity running the process.</td>
<td>• Flowgate review should be done consistent with the IDC summer/winter base case changes, which would occur twice per year instead of Quarterly. Each base case update done at NERC for the IDC will need a certain amount of review just to make sure that current Flowgates will continue to function with the new model. The FGs will be run through the process summarized in figure C-1.</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Monthly update of the Book of Flowgates and Data Exchange</td>
<td>Take monthly updates from book of Flowgates, monthly full files and monthly incremental files and run them through the Flowgate process and tests.</td>
<td>• Monthly the Reciprocal Entities will perform full Flowgate updates and synchronization. In addition the NERC Book of Flowgates is updated once a month. We will run these changes through the process summarized in figure C-1.</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Customer FG Requests</td>
<td>Any customer FG requests will also be subject to the tests and process above.</td>
<td>• Any customer FG requests will be run through the process summarized in figure C-1.</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Temporarily Flowgate added by Reciprocal Entity</td>
<td>Any temporary Flowgate added by a Reciprocal Entity will also be subject to the tests and processes in Step 5.</td>
<td>• Any temporary Flowgates added by a Reciprocal Entity will be run through the process summarized in figure C-1</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Run Through FG Process and Tests</td>
<td>Run through FG Determination Process, figure C-1</td>
<td>• Any FGs being reviewed or added will be run through the process summarized in figure C-1.</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>AFC/CF/RCF List</td>
<td>Any FG additions or modifications would need to be committed to the repository of FGs and their qualifications.</td>
<td>• Any FG additions or modifications would need to be committed to the repository of FGs, along with their qualifications.</td>
<td></td>
</tr>
</tbody>
</table>

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Appendix D – Training

The concepts in these proposals should not have a significant impact upon system operators beyond the operators of the Operating Entity. The reason that this impact rests upon the Operating Entities is that the Operating Entities Operators will need to be trained to monitor and respond to the external Flowgates.

Reliability Coordinator (RC) Operator Training Impacts include:

1. The ability to recognize and respond to Coordinated Flowgates.
   a. IDC outputs will show schedule curtailments and possible redispatch requirements.
   b. Must be able to enter constraint in systems to provide the redispatch relief within 15 minutes.
   c. Must be able to confirm that the required redispatch relief has been provided and data provided to the IDC.

2. Capability to enter Flowgates on the fly.

Other RC System Operators Training Impacts include:

1. The ability to take projected net system flows between an Operating Entity’s Control Zones versus only tag data to run day-ahead analysis (data to be provided by the IDC).

2. Need to develop a working knowledge of how relief on a TLR Flowgate can come from both schedule changes and redispatch on a select set of Coordinated Flowgates.

3. Can coordinate with another RC Operator when the RC System Operator has a temporary Flowgate that they believe requires the implementation of the “Flowgate on the Fly” process.

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Appendix F – FERC RCF Dispute Resolution

RCF Dispute Resolution

If a Party has followed all processes in the disputed flowgate process outlined in section 3.2 and is dissatisfied with the ORS resolution of the flowgate dispute, the Party may refer the dispute to FERC’s Dispute Resolution Service for mediation, and upon a Party’s determination at any point in the mediation that mediation has failed to resolve the dispute, either Party may seek formal resolution by initiating a proceeding before FERC.

Allocation Adjustment for New Transmission Dispute Resolution

If a Party has followed all processes in the Allocation Adjustment Peer Review process outlined in Appendix G and is dissatisfied with the resolution of the Congestion Management Process Council (CMPC), the Party may refer the dispute to FERC’s Dispute Resolution Service for mediation, and upon a Party’s determination at any point in the mediation that mediation has failed to resolve the dispute, either Party may seek formal resolution by initiating a proceeding before FERC.

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Appendix G – Allocation Adjustment for New Transmission Facilities and/or Designated Network Resources

Midwest ISO and PJM utilize the same Guiding Principles as other Reciprocal Entities for Allocation Adjustment for New Transmission Facilities and/or Designated Network Resources. In addition, Midwest ISO and PJM have established procedures for allocation adjustments based on cross-border cost sharing and for determining the builder for the new transmission service or upgrades.

1. Guiding Principles

The following guiding principles will be used in determining the allocation adjustments for New Transmission Facilities and/or Designated Network Resources.

- **Principle 1 (Non-builder held harmless)** – To the extent possible, the non-building entity will receive the same overall impacts in its allocations.
- **Principle 2 (Builder receives benefits)** – To the extent possible, the building entity will receive any benefit to the transmission system that result from the system upgrade.

To the extent these two principles conflict, the Non-Builders Held Harmless Principle will have priority over the Builder Receives Benefit Principle.


To the extent a new transmission facility causes a significant decrease in flow on a Reciprocal Coordinated Flowgate the change in the allocation will be assigned to the Party responsible for the new facility. Otherwise, the normal allocation procedures will be followed and no allocation adjustments for new transmission facilities will be made.

Significant impact is defined as a 3% change in flow that occurs to an OTDF Flowgate and a 5% change in flow that occurs to a PTDF Flowgate with the addition of the new facility. The 3% and 5% are measured as a percentage of the Flowgate TTC (sometimes called Total Flowgate Capability (TFC)).

The allocation adjustment will be assigned to the Party responsible for the new facility. Both the original allocation and the allocation adjustment are assigned to the Reciprocal Entities. When the term “Party responsible for the new facility” is used in this process, it refers to the Reciprocal Entity with functional control of the new transmission facility. To the extent a group of transmission owners installs a new facility that includes multiple Reciprocal Entities and the new transmission facility results in a change in transfer capability on one or more RCFs, these Reciprocal Entities will work in collaboration to determine appropriate adjustments to each Reciprocal Entity’s allocation on all significantly impacted RCFs.
An analysis will be performed both with and without the new facility to determine whether there is a significant impact on one or more RCFs. The analysis and any subsequent allocation adjustments will coincide with the expected in-service date of the new facility. The inclusion of the new transmission facility in such an analysis is dependent on having a commitment that the new facility has or is expected to receive all of the appropriate approvals and will be installed on the date indicated.

In order to qualify for an allocation adjustment, the new transmission facility must not only create a significant change in flows, it must also be a significant change to the transmission system (i.e. a new line or transformer that creates a significant change to flows on one or more RCFs). The addition of a new generator without transmission additions (other than the generation interconnection) is not covered by this process for new transmission facility additions. A change in the rating of an RCF may qualify as a significant change to the transmission system and be eligible to receive an allocation adjustment even though it does not result in a change in flows.

For stability limited Flowgates, a new generator, reactive device or change to a remedial action scheme may contribute to a change in the transfer limitation of stability limited Flowgates. Where this occurs and the addition is being made for the specific purpose of changing the transfer limitation of stability limited Flowgates, an allocation adjustment will be provided to the Reciprocal Entity responsible for the new generator, reactive device or change to a remedial action scheme. By receiving an allocation adjustment, this new generator, reactive device or change to a remedial action scheme will not also be included in the historical usage calculation to avoid double-counting of the impacts.

Not all new transmission facilities that significantly impact RCFs involve a change in flows. A new facility may be added that changes the rating of an RCF but has minimal impact on the flow (i.e. reconductoring, replacing a wave trap (WT) or current transformer (CT), replacing a transformer). In this case, each Reciprocal Entity’s historical usage flow will remain constant but the rating of the Flowgate will either increase or decrease. The Reciprocal Entity responsible for the new facility will receive an allocation adjustment for rating increases. There will be no allocation adjustments for rating decreases.

There is an equity issue involving new transmission facilities that result in an increased rating. Where a new facility involves minimal cost change (such as replacing either a WT or CT, replacing a jumper, replacing a switch, changing a CT setting, etc.), there have already been significant costs incurred on a larger conductor that allows the increased rating to occur. As long as the Reciprocal Entity making the minimal cost change is also responsible for the conductor, it is the appropriate Reciprocal Entity to receive the allocation adjustment. However, if different Reciprocal Entities own the conductor versus are responsible for making the minimal cost change, there is an equity issue if the entire allocation adjustment is given to the Reciprocal Entity responsible for making the minimal cost change. The Reciprocal Entities shall negotiate a mechanism to share in the allocation adjustment.


Where a new transmission facility is added as part of an approved new usage of the transmission system (either a new DNR or a new Firm Transmission Service), the Reciprocal Entity
responsible for the new facility has two choices on the treatment of this combination. First, in recognition that they have addressed transmission concerns associated with the new DNR or new Firm Transmission Service, the combination of the new transmission facility and new DNR/Firm Transmission Service will be added to the base model used in the historic usage impact calculation. The new DNR or new Firm Transmission Service will be treated as if it met the Freeze Date. To the extent the new transmission facility and its associated new DNR or new Firm Transmission Service will not occur until a future time period, they will not appear in the historic usage impact calculation until after the in-service/start date. The inclusion of the new transmission facility and associated DNR/Firm Transmission Service is dependent on having a commitment that both have been approved and will occur on the date indicated. If no such commitment exists, these additions will not be included in the historic usage impact calculation. By making this choice to include the new transmission facility and DNR/Firm Transmission Service in the historic usage impact calculation, the NNL allocation will consider the impact of both. This may result in increased NNL allocation to all Reciprocal Entities after considering historic usage impacts (down to 0%). However, the Reciprocal Entity that builds the new transmission facility will not receive any special treatment (NNL allocation adjustment) because of the new transmission facility. This inclusion of a new DNR or new Firm Transmission Service only applies where associated new transmission facilities have been added to accommodate the new transmission usage.

Second, the Reciprocal Entity that builds the new transmission facility associated with a new DNR or new Firm Transmission Service can receive an NNL allocation adjustment and must honor that allocation when they apply the new DNR or new Firm Transmission Service in their use of NNL allocations. The Reciprocal Entity determines the impact of the new transmission facility without the new DNR or new Firm Transmission Service to calculate any adjustments to the NNL allocations (the same process documented in the previous section “New Transmission Facilities that Do Not Involve New DNRs or New Firm Transmission Service”). The Reciprocal Entity will use the remaining NNL allocation that has not been committed to other uses for the new DNRs or new Firm Transmission Service.

The Reciprocal Entity responsible for the combination of new transmission facility and new DNR/Firm Transmission Service will make a single choice (either one or two) that applies to all RCFs that are significantly impacted by the combination. There is no opportunity to have a different selection on different RCFs that are all impacted by the same combination.

4. Allocation Adjustment Peer Review

When reviewing the allocation adjustments, if an impacted Reciprocal Entity finds a situation where the rule set does not produce a satisfactory outcome, the impacted Reciprocal Entity may request a review by the CMPWG. The impacted Reciprocal Entity will present the unsatisfactory results and a proposed alternative. If the CMPWG agrees to the proposed alternative it will be implemented as an exception, and the CMPC will be notified of the exception prior to implementation. If the CMPWG does not agree, the impacted Reciprocal Entity can seek further review by the CMPC. The impacted Reciprocal Entity will present its proposed alternative and the CMPWG member(s) will present their concerns to the Council for the Council to take action. All exceptions approved by the CMPWG or CMPC will be documented for future reference.
Depending on the nature of the upgrade, the impact of the new facility will be held in abeyance pending completion of the review. This means for a rating change, the prior rating will continue to be used in the model update process pending completion of the review. This means for a flow change, the new facility will be recognized in the model update process. The impacts will be calculated using the normal (socialized) allocation process and no allocation adjustments will be made pending completion of the review. These reviews should be completed in a timely manner.

5. **Allocation Adjustments Based on Cross-Border Cost Sharing**

The physical rights to any significantly impacted incremental capacity on existing RCFs, that is a result of the cross-border allocation process ("allocation adjustment"), will be assigned to a Party, for congestion management purposes, in proportion to the share of the costs that such Party must pay under the cost allocation process in Section 9.4.3.2 of the JOA.

An allocation adjustment based on the share of costs that such Party must pay under the cost allocation process in Section 9.4.3.2 of the JOA will apply only where there has been a significant decrease in flows on an existing RCF.

An analysis will be performed both with and without the new facility to determine whether there is a significant impact on one or more RCFs. The analysis and any subsequent allocation adjustments will coincide with the expected in-service date of the new facility. The inclusion of the new transmission facility in such an analysis will be dependent upon having a commitment that the new facility has or is expected to receive all of the appropriate approvals and will be installed on the date indicated.

6. **Determination of Builder in the Flowgate Allocation Process**

For Midwest ISO and PJM, flowgate allocations are used to sell firm transmission service and to prioritize market flows reported to the IDC that are then subject to curtailment during TLR. At the same time, flowgate allocations are also used in the market-to-market settlement process and in the ARR, FTR, and day-ahead market loop flow modeling between Midwest ISO and PJM. The firm flow entitlement used in market-to-market settlement and in the ARR, FTR, and day-ahead market loop flow modeling is derived from a combination of flowgate allocations in the forward direction and market flow impacts in the reverse direction. This allocation agreement between Midwest ISO and PJM is limited to how to assign allocations and does not extend into ARRs, FTRs, and day-ahead market loop flow assumptions.

In order to implement the allocation process, Midwest ISO and PJM have defined the terms builder and non-builder as follows when applying the allocation adjustment rules:

- The term builder always refers to a Party that has responsibility (either total or partial) for the transmission facility upgrade and is entitled to receive the increase in capacity of existing flowgates while holding the non-builders harmless.
- In determining which Party has total or partial responsibility for the transmission facility upgrade, responsibility is defined as the Party that has cost responsibility for the upgrades. The cost responsibility could be to a single Transmission Owner pricing zone within a market footprint, to multiple Transmission Owner pricing zones within the same...
market footprint, to multiple Transmission Owner pricing zones within both market footprints as in the case of a cross-border project funded by the two markets, or to a single market participant as in the case of a transmission upgrade funded by a market participant.

- Where the responsibility for cost is to either a single Transmission Owner pricing zone or to multiple Transmission Owner pricing zones within the same market footprint in which the upgrade is built, the total allocation goes to the builder after holding the non-builder harmless.

- Where the responsibility for cost is shared by multiple Transmission Owner pricing zones within both market footprints, the allocation will be split between the Parties in proportion to the cost responsibility between the Parties.

- Where the responsibility for cost is to a single market participant funder (rather than to an entire pricing zone) that has resources/participates in one market only, the allocation goes to that market, irrespective of the Party that owns the flowgate and in which the upgrade resides.

- Where the responsibility for cost is to a market participant funder that has resources/participates in both markets, the allocation will be split between the two markets subject to the Parties’ OATT.

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Appendix H Application of Market Flow Threshold Field Test Conditions Version: 0.0.0

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Appendix H – Application of Market Flow Threshold Field Test Conditions

Midwest ISO, PJM and SPP participated in a NERC approved Market Flow threshold field test from June 1, 2007 to October 31, 2009. The purpose of the field test was to determine a Market Flow threshold percentage that allows the three Regional Transmission Organizations (RTOs) to consistently meet their relief obligations during TLR without jeopardizing reliability. Although the field test was able to achieve a success rate close to 100% based on Midwest ISO data using a 5% threshold, the following conditions were applied to the field test results:

- Market Flows were evaluated 30 minutes after implementation of the TLR curtailment.
- A 5 MW dead-band (or 10% of the relief obligation for relief obligations greater than 50 MW) was applied to the Target Market Flow such that once actual Market Flows were within the dead-band, it was considered a success meeting the relief obligation.
- There were no instances where Midwest ISO was able to meet its relief obligation if more than 30 MW must be removed within 30 minutes. The field test found the amount of Market Flow that must be removed in 30 minutes and not the size of the relief obligation is an indicator whether the market will be successful.

Since the NERC ORS applied the three conditions above to the field test results in order to demonstrate a high success rate, these same conditions will be applied when the Market-Based Operating Entities have relief obligations on external flowgates during TLR.

The field test results are only applicable to Flowgates that are external to each of the RTOs and does not include internal Flowgates (internal to that specific RTO) or market-to-market Flowgates (internal to one of the three RTOs but subject to market-to-market provisions with another RTO). The reason for excluding internal Flowgates and market-to-market Flowgates is because the three RTOs use market redispatch to control total flow and to maintain reliability. As the Reliability Coordinator for the Flowgate, the three RTOs are responsible for the reliability of their own Flowgate and must manage total flow in order to meet their reliability responsibility. As described in the field test final report, by controlling total flow, the three markets effectively meet their relief obligation.

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ATTACHMENT 3 INTERREGIONAL COORDINATION PROCESS Version: 0.0.0

Effective: 6/16/2011

Midwest ISO
Second Revised Rate Schedule FERC No. 5
PJM Interconnection, L.L.C.
Second Revised Rate Schedule FERC No. 38

ATTACHMENT 3

Interregional Coordination Process

Version 3.0

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
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1  Overview of the Market-to-Market Coordination Process
2  Interface Bus Price Coordination
3  Real-Time Energy Market Coordination
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Appendix A: Definitions

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Preface

The purpose of this Interregional Coordination Process (“ICP”) is to provide a description of the proposed market-to-market coordination process, including the appropriate use of the market-to-market process, that will be implemented concurrently with the implementation of side-by-side LMP-based energy markets in the PJM and Midwest ISO regions. Specifically, this ICP presents an overview of the market-to-market coordination process, an explanation of the coordination for market pricing at the regional boundaries, a description of the Real-Time and Day-Ahead coordination methodologies, an example to illustrate the Real-Time coordination, and the associated settlements processes.

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Section 1 Overview of the Market-to-Market Coordination Process Version:

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1 Overview of the Market-to-Market Coordination Process

The fundamental philosophy of the PJM/Midwest ISO interregional transmission congestion coordination process is to set up procedures to allow any transmission constraints that are significantly impacted by generation dispatch changes in both markets to be jointly managed in the security-constrained economic dispatch models of both RTOs. This joint management of transmission constraints near the market borders will provide the more efficient and lower cost transmission congestion management solution, while providing coordinated pricing at the market boundaries.

The market-to-market coordination process builds upon the PJM/Midwest ISO market-to-non-market coordination process, as described in the “Congestion Management Process” document (“CMP”) filed as part of the Midwest ISO – PJM Joint Operating Agreement. That CMP describes the interregional coordination process between a market region that uses an LMP-based congestion management regime and a non-market region that uses a TLR-based congestion management regime (i.e., a market to non-market interface). As described in the CMP, the set of transmission flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market is identified as the set of Reciprocal Coordinated Flowgates (RCFs). These RCFs are then monitored to measure the impact of market flows and loop flows from adjacent regions. The CMP describes how the market flow impacts will be managed on an interregional basis within the existing NERC IDC to enhance the effectiveness of the NERC interregional congestion management process. The CMP also describes a process for calculating flow entitlement for network and firm transmission utilization in one region on the RCFs in an adjacent region.

The market-to-market coordination process builds on the work already completed, as described above, by adapting the coordination, as appropriate, to the conditions that will prevail after both the PJM and Midwest ISO markets are implemented in the Midwest. In addition, there is a continuing need to define the flow entitlement for network and firm transmission utilization in one region on the subset of RCFs called M2M Flowgates in an adjacent region.

- **Real-Time Energy Market Coordination** -- The market-to-market coordination focuses primarily on Real-Time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. This Real-Time coordination will result in a more efficient economic dispatch solution across both markets to manage the Real-Time transmission constraints that impact both markets, focusing on the actual flows in Real-Time to manage constraints. Under this approach, the flow entitlements on the M2M Flowgates do not impact the physical dispatch; the flow entitlements are used in market settlements to ensure
appropriate compensation based on comparison of the actual market flows to the flow entitlements.

- **Day-Ahead Energy Market Coordination** -- The Day-Ahead market coordination focuses primarily on ensuring that the Day-Ahead scheduled flows on all M2M Flowgates are limited to no more than the Firm Flow entitlements for each RTO. Under certain conditions, an RTO may request that the Day-Ahead flow limit be raised above its Firm Flow entitlement but this is expected to happen only by exception under abnormal conditions.

- **ARR Allocation & FTR Auction Coordination** -- The Annual Revenue Rights Allocation and Financial Transmission Rights (FTR) auction processes in both RTOs will model the Firm Flow entitlements on all M2M Flowgates.

1.1 Only a subset of all transmission constraints that exist in either market will require coordinated congestion management. This subset of transmission constraints will be identified as M2M Flowgates in a manner similar to the method used in the CMP described above. The list of M2M Flowgates will be limited to only those for which at least one generator in the adjacent market has a significant Generation-to-Load Distribution Factor (GLDF), sometimes called “shift factor,” with respect to serving load in that adjacent market. NERC rules currently establish that a significant shift factor is five percent or greater. If NERC adopts a lower threshold than 5%, the new threshold will be used to determine whether the generator has a significant GLDF for the purpose of this market-to-market ICP. Flowgates eligible for market-to-market coordination are called M2M Flowgates. For the purposes of market-to-market coordination (in addition to the four studies for RCFs described in section 3.2.1 of the CMP) the following will be used in determining M2M Flowgates.

1.1.1 M2M Flowgates include Reciprocal Coordinated Flowgates and any additional Flowgates that meet the criteria in this section (1.1) of the Interregional Coordination Process.

1.1.2 Midwest ISO and PJM will only be performing market-to-market coordination on RCFs that are under the operational control of Midwest ISO or PJM. Midwest ISO and PJM will not be performing market-to-market coordination on Flowgates that are owned and controlled by third party entities or on Flowgates that are only considered to be coordinated Flowgates.

1.1.3 Where the adjacent market does not have a generator with significant impact on a single-monitored element Flowgate (i.e. shift factor is less than 5%) but its market flows are a significant portion of the total flow (greater than 25% of the Flowgate rating), these transmission constraints will be included in the list of M2M Flowgates subject to market-to-market coordination. If the market flow impacts of the Non-Monitoring RTO exceed 25% of the Flowgate rating during real-time operations, the Flowgate will be added as a M2M Flowgate at the request of the Monitoring RTO.

1.1.4 The Parties will lower their generator binding threshold to match the lower generator binding threshold utilized by the other Party. The generator binding threshold will not be set below 1.5% except by mutual consent. (This requirement
applies to M2M Flowgates. It is not an additional criteria for determination of M2M Flowgates.)

1.1.5 For the purpose of determining whether a multi-monitored element Flowgate is eligible for market-to-market, a progressive threshold based on the number of monitored elements will be used: a single monitored element Flowgate will use a 5% shift factor threshold; double monitored element Flowgate will use a 7.5% shift factor threshold; and a Flowgate with three monitored elements will use a 10% shift factor threshold. Flowgates with more than three monitored elements will be used only by mutual agreement.

1.2 M2M Flowgate Studies

During the M2M Flowgate Studies, a M2M Flowgate may be added to the systems for operations control using the actual monitored /contingent element pair. Settlements will be implemented using a hold harmless approach as described in the After the Fact Review process set forth in Section 8.4 below.

1.2.1 Midwest ISO and PJM will implement a process whereby either RTO may request the other to enter an anticipated M2M Flowgate into the dispatch tools before the completion of the Flowgate studies when a system event requires prompt attention. Binding on the Flowgate may commence as soon as each entity's operators can make the monitored/contingent element pair available in its system. Firm Flow Entitlements shall be applied and settlements calculated after the M2M Flowgate is approved by both entities.

1.2.2 Use of a M2M Flowgate Before Completion of the Studies:
The use of an anticipated Flowgate while the Flowgate is undergoing the M2M Flowgate Studies is described in CMP Section 3.2.5 Dynamic Creation of Coordinated Flowgates. These will typically be limited to forced outages since there should be time to evaluate the potential new M2M Flowgate before the planned outage is taken. However, the need for a new Flowgate is not always identified in advance. The Parties will ensure the time period to run the coordinated Flowgate test and have these Flowgates ready for the market-to-market process is as short as possible.

1.3 Removal of M2M Flowgates

Removal of M2M Flowgates from the systems may be necessary under certain conditions including the following:

1.3.1 Where Information Technology systems cannot support the operation of a defined M2M Flowgate effectively, the first attempt will be to find a mutually acceptable temporary work-around that will allow the continued use of the market-to-market process. Where a temporary work-around is not available, the market-to-market process will be suspended on that M2M Flowgate until Information Technology system enhancements allow re-establishing the M2M Flowgate. The Party
responsible for IT system enhancements will take all practicable steps to minimize the period of the suspension.

1.3.2 A M2M Flowgate is no longer valid when either a temporary M2M Flowgate or a transmission system change is implemented that eliminates significant impacts from either entity’s generation such that the Flowgate no longer passes the M2M Flowgate Studies.
   a. Once a M2M Flowgate becomes a completely invalid constraint, it will no longer be bound in the monitoring RTO’s UDS.
   b. A Flowgate that is removed from the M2M Flowgate list but remains a valid constraint may continue to be bound in the Monitoring RTO’s UDS, but the market-to-market process will no longer be initiated on it.

1.3.3 The RTOs will collaborate to address specific scenarios where generation is not responding to dispatch signals (e.g., self scheduled) and the generation does, or could, significantly impact an M2M Flowgate and/or resulting market-to-market settlement.

1.3.4 The Parties can mutually agree to add or remove a Flowgate from the market-to-market process whether or not it passes the coordination tests, or whether or not it is a Reciprocal Coordinated Flowgate. A M2M Flowgate may be removed when the Parties agree that the market-to-market process would not be an effective mechanism to manage congestion on that Flowgate.

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Interface Bus Price Coordination

Proxy bus prices are calculated by each RTO to reflect the economic value of imports or exports from the neighboring RTO. For example, the proxy bus price for RTO A as calculated by RTO B is driven by the economic dispatch of RTO B, therefore this proxy price will reflect the system marginal price in RTO B, plus any congestion cost adjustment and marginal loss cost adjustment based on the proxy bus location. The coordinated operation of M2M Flowgates will tend to force the pricing at the RTO borders to be consistent with the energy prices at generators and load busses near the RTO border points.

In order to be good functional indicators for the market-to-market coordination, the proxy bus models for PJM and Midwest ISO must be coordinated to the same level of granularity. Therefore, the proxy bus modeling approaches must be similar such that the prices are consistent. This does not necessarily mean the proxy bus prices will be the same, particularly in the initial implementation of Market-to-Market coordination. What is important at the outset is that the proxy buses reflect consistent pricing between the RTOs given the constraints for which each RTO is operating. Consistency means that the proxy bus price one RTO calculates for the other RTO reflects the nature of the congestion on both RTOs’ systems, such that imports and exports to and from one RTO to the other are provided the correct incentives given their effect on the current binding constraints. A description of the current proxy bus modeling process used by PJM and Midwest ISO is posted on each RTO’s OASIS.

As the Market-to-Market coordination process continues to evolve, it may be possible to get to the point that each RTO’s proxy bus prices for the other is consistently close. This will require coordination beyond merely operating for constraints on each other’s systems, to include tightly coordinating the economic dispatches themselves, in an iterative process as described in Section 7.

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Section 3 Real-Time Energy Market Coordination Version: 0.0.0 Effective:

6/16/2011

3 Real-Time Energy Market Coordination

When an M2M Flowgate that is under the operational control of either Midwest ISO or PJM become binding in the Monitoring RTOs Real-Time security constrained economic dispatch, the Monitoring RTO will notify the Non-Monitoring RTO of the transmission constraint violation and will identify the appropriate M2M Flowgate that requires mitigation. The Monitoring and Non-Monitoring RTOs will provide the economic value of the constraint (i.e., the shadow price) as calculated by their respective dispatch models. Using this information, the security-constrained economic dispatch of the Non-Monitoring RTO will include the transmission constraint; the Monitoring RTO will evaluate the shadow prices within each RTO and request that the Non-Monitoring RTO reduce its market flow if it can do so more efficiently than the Monitoring RTO (i.e., the Non-Monitoring RTO has a lower shadow price than the Monitoring RTO).

An iterative coordination process will be supported by automated data exchanges in order to ensure the process is manageable in a Real-Time environment. The process of evaluating the shadow prices between the RTOs will continue until the shadow prices are sufficiently close that an efficient redispatch solution is achieved. The continual interactive process over the next several dispatch cycles will allow the transmission congestion to be managed in a coordinated, cost-effective manner by the RTOs. A more detailed description of this iterative procedure will be discussed in Section 3.1.

This coordinated dispatch protocol will be performed any time that an M2M Flowgate under the operational control of either Midwest ISO or PJM becomes binding. This approach will produce the level of coordination that will be required to ensure efficient congestion management across the market seams. This approach also will provide a much higher level of interregional congestion management coordination than that which currently exists between any existing adjacent markets.

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3.1 Real-Time Energy Market Coordination Procedures

The following procedure will apply for managing M2M Flowgates in the real-time energy market:

1. The RTOs will exchange topology information to ensure that their respective market software is consistent.

2. When any of the M2M Flowgates under a Monitoring RTO’s control is identified as a transmission constraint violation, the Monitoring RTO will enter the M2M Flowgate into its security-constrained dispatch software, setting the flow limit equal to the appropriate facility rating.

3. The Monitoring RTO will then notify the Non-Monitoring RTO of the transmission constraint violation and will identify the appropriate M2M Flowgate that requires mitigation.

4. When the M2M Flowgate first becomes a binding transmission constraint in the Monitoring RTOs Real-Time security-constrained economic dispatch, the Monitoring RTO will transmit the following information to the Non-Monitoring RTO:
   - Constraint Shadow Price ($/MW) - output of the RTOs Real-Time market software.
   - Current Market Flow contribution by the Monitoring RTO on M2M Flowgate (MW) - output of the Real-Time market software.
   - Amount of MWs requested to be reduced from the current market flow of the Non-Monitoring RTO. This number will change throughout the iterative process to efficiently resolve constraints.

5. The Non-Monitoring RTO will enter the M2M Flowgate into its security-constrained dispatch software, setting the flow limit on the M2M Flowgate equal to its current market flow minus the relief requested by the Monitoring RTO.
   (a) This means the Non-Monitoring RTO will attempt to manage the flow on the M2M Flowgate at its current Market Flow amount or less, such that it will not contribute any additional flow on the limited M2M Flowgate during this time period.

6. If the Non-Monitoring RTO has sufficient generation to be redispatched, it will redispatch its generation to control the M2M Flowgate until one of the following conditions is reached:
   (a) The Non-Monitoring RTO has provided the relief requested by the Monitoring RTO.
The Non-Monitoring RTO has provided relief at a cost as high as the current shadow price from the Monitoring RTO.

7. The Non-Monitoring RTO will then transmit the following information to the Monitoring RTO:

- **Constraint Shadow Price ($/MW)** - Output of the RTOs Real-Time market software. (If the M2M Flowgate does not result in a binding constraint in the Non-Monitoring RTO’s security-constrained economic dispatch, then the shadow price is zero and the Flow Relief is zero for the Non-Monitoring RTO.)

- **Current market flow contribution by the Non-Monitoring RTO on M2M Flowgate (MW)** - Output of the RTO’s Real-Time market software.

8. Over the next several dispatch cycles the Monitoring RTO may request the Non-Monitoring RTO to adjust its flow limit up or down. The Monitoring RTO will continue to control the M2M Flowgate respecting the appropriate rating of the facility.

9. As the relief provided by the Non-Monitoring RTO is realized in the M2M Flowgate, the Monitoring RTO can control the M2M Flowgate at a lower shadow price since less relief is needed from the Monitoring RTO. The updated shadow price will be sent to the Non-Monitoring RTO. The Non-Monitoring RTO will then control the M2M Flowgate using the latest shadow price from the Monitoring RTO as the shadow price limit.

10. Throughout the period that the transmission constraint violation exists, the RTOs will continue to share the flow and constraint shadow price information that is described above. The shadow prices of the two RTOs will eventually converge towards the most cost-effective redispatch solution, provided both RTOs have sufficient redispatch capability. The information transferred via these data exchanges will be retained to provide the pertinent data for Market Settlements.

11. Every 15 to 30 minutes as necessary, the Monitoring RTO will review the constraint shadow price comparison, make required adjustments, and communicate any such adjustments to the Non-Monitoring RTO. This process will continue until the Monitoring RTO determines that the cost of further adjustments to the dispatch of the Non-Monitoring RTO would exceed the cost of relieving the transmission constraint by adjusting the Monitoring RTO’s own dispatch.

12. The start and stop times for such Constrained Operation events involving M2M Flowgates will be logged for Market Settlements purposes.

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3.2 Real-Time Energy Market Settlements

The Market Settlements under the coordinated congestion management will be performed based on the Real-Time Market Flow contribution on the transmission flowgate from the Non-Monitoring RTO as compared to its flow entitlement.

If the Real-Time Market Flow is greater than the flow entitlement plus the Approved MW adjustment from Day Ahead Coordination, then the Non-Monitoring RTO will pay the Monitoring RTO for congestion relief provided to sustain the higher level of Real-Time market flow. This payment will be calculated based on the following equation:

\[ \text{Payment} = (\text{Real-Time Market Flow MW}^1 - (\text{Firm Flow Entitlement MW}^2 + \text{Approved MW}^3)) \times \text{Transmission Constraint Shadow Price in Monitoring RTOs Dispatch Solution} \]

If the Real-Time Market Flow is less than the flow entitlement plus the Approved MW adjustment from Day Ahead Coordination, then the Monitoring RTO will pay the Non-Monitoring RTO for congestion relief provided at a level below the flow entitlement. This payment will be calculated based on the following equation:

\[ \text{Payment} = ((\text{Firm Flow Entitlement MW}^2 + \text{Approved MW}^3) - \text{Real-Time Market Flow MW}^1) \times \text{Transmission Constraint Shadow Price in Non-Monitoring RTOs Dispatch Solution} \]

For the purpose of settlements calculations, shadow prices will be calculated by the pricing software in the same manner as the LMP, and will be integrated over each hour during which a transmission constraint is being actively coordinated under the ICP by summing the five-minute shadow prices during the active periods within the hour and dividing by 12 (the number of five minute intervals in the hour).

---

1 This value represents the Non-Monitoring RTO’s Real Time Market Flow.
2 This value represents the Non-Monitoring RTO’s Firm Flow Entitlement.
3 This value represents the Approved MW that resulted from the Day Ahead Coordination.
4 Day-Ahead Energy Market Coordination

The Day-Ahead energy market coordination focuses primarily on ensuring that the Day-Ahead scheduled flows on all M2M Flowgates are limited to no more than the Firm Flow Entitlements for each RTO. When system conditions can accommodate the change, either RTO may request that the Day-Ahead flow limit be raised above its Firm Flow Entitlement. Normally, this protocol will be utilized infrequently and only when the need for additional congestion relief assistance is predictable on a Day-Ahead basis.

The Day-Ahead energy market redispatch protocol may be implemented in the Day-Ahead energy market upon the request of either RTO if the adjacent RTO verifies that such Day-Ahead redispatch is feasible.

An example of the Day-Ahead energy market protocol is as follows:

1. The Requesting RTO specifies the amount of scheduled flow reduction that it is requesting on a specific M2M Flowgate and communicates the request to the Responding RTO.

2. The Responding RTO will then lower the MW limit that it utilizes in its Day-Ahead market on the specified M2M Flowgate by the specified amount. This means that instead of modeling the M2M Flowgate constraint at flow entitlement amount, the Responding RTO will model the constraint as the flow entitlement less the requested MW reduction. Therefore, the Responding RTO will schedule less flow on the specified M2M Flowgate in order to provide Day-Ahead congestion relief for the Requesting RTO. The Requesting RTO may then use the additional MW capability in its own Day-Ahead market.

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4.1 Day-Ahead Energy Market Coordination Procedures

The following procedure will apply to the modeling of M2M Flowgates in the Day-Ahead energy markets, unless either the Monitoring RTO or the Non-Monitoring RTO requests specific exceptions.

- Each RTO will model all M2M Flowgates, for which it is the Reliability Coordinator, in its Day-Ahead market and Day-Ahead reliability analyses, with the limit set equal to the applicable facility limit less the Firm Flow Entitlement of the Non-Monitoring RTO.

- Each RTO will model all M2M Flowgates, for which it is NOT the Reliability Coordinator, in its Day-Ahead Market and Day-Ahead reliability analysis with the limit set equal to its Firm Flow Entitlement for that M2M Flowgate.

- The Monitoring RTO will include an appropriate loop flow model in its Day-Ahead process. However, this loop flow model will not account for loop flows contributed by deliveries associated with the Non-Monitoring RTO market since these flows are accounted for by the Firm Flow Entitlement.

An M2M Flowgate limit exception is a request to alter the M2M Flowgate limits, as described above, that will be modeled in the Day-Ahead markets and/or the Day-Ahead reliability analysis. The following procedure will apply for designating M2M Flowgate limit exceptions:

1. Prior to 0800 EST on the day before the Operating Day, if the Requesting RTO identifies a need to utilize more of an M2M Flowgate than it is entitled, it may request the Responding RTO to lower its Day-Ahead Market limit below its Firm Flow Entitlement by a specified amount for a specified range of hours.

2. If the Responding RTO agrees to provide the limit reduction, it will communicate the approved amount to the Requesting RTO by 1000 EST.

3. The Requesting RTO may increase its limit on the M2M Flowgate by the specified amount for the specified range of hours.

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4.2 Day-Ahead Energy Market Settlements

The market settlements for Day-Ahead congestion relief will be performed in a similar manner to the Real-Time energy market settlements of the coordinated congestion management protocol. The Day-Ahead payment for the RTO that is requesting congestion relief will be calculated as follows:

\[
\text{Requesting RTO Payment to Responding RTO} = \text{Approved Day-Ahead Adjustment for M2M Flowgate} \times \text{Responding RTOs M2M Flowgate constraint shadow price.}
\]

This payment will be calculated based on the hourly Day-Ahead Market results. If such congestion relief is requested and performed on a Day-Ahead basis, then the Real-Time flow entitlement for the affected hours in the corresponding Real-Time market will be adjusted accordingly.

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Section 5 Annual Revenue Rights (ARR) Allocation/Financial Transmission Rights (FTR) Auction Coordination

The allocation of ARR and FTR products in each marketplace must recognize the flowgate entitlement that exists in adjacent markets. The ARR allocation and FTR Auction model will contain the same level of detail for adjacent regions as the Day-Ahead market model and the Real-Time market model. Each RTO will allocate ARRs via Annual ARR Allocation award, and award FTRs via Annual and Monthly FTR Auction to Network and Firm Transmission customers subject to their participation and simultaneous feasibility test that determines the amount of transmission capability that exists to support the ARRs and FTRs.

The simultaneous feasibility analysis for each RTO will model that RTO’s flow entitlement on the transmission flowgates in the adjacent region as the market flow limit that must be respected in the ARR Allocation and FTR Auction processes. The transmission flowgates in each RTO will be modeled in the simultaneous feasibility test at a capability value equal to the flowgate rating minus the flow entitlement that exists for flows from the adjacent market. In this way, the ARR Allocation and the FTR Auction across both RTOs will recognize the reciprocal transmission utilization that exists for Network and Firm transmission customers in both markets.

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6 Coordination Example

The following example illustrates the Real-Time coordination of an M2M Flowgate, specifically describing the following five stages:

- **Stage 1: Initial Conditions & Energy Prices at Border**
- **Stage 2: Transmission Constraint Initialization & Energy Prices at Border**
- **Stage 3: First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Monitoring RTO) & Energy Prices at Border**
- **Stage 4: First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Non-Monitoring RTO) & Energy Prices at Border**
- **Stage 5: Ongoing Coordinated Dispatch Cycles**

**Stage 1 – Initial Conditions**

- Marginal Losses are not utilized in this example for ease of understanding
- RTO A is the Non-Monitoring RTO, its system marginal price is $35/MWh
- RTO B is the Monitoring RTO, its system marginal price is $40/MWh
- Generator 1 is on-line and dispatched to full output, its dispatchable range is 100 MW
- Generators 2 and 3 are both off-line; they are both 20 MW quick start CTs
- M2M Flowgate A has a limit of 100 MW with the actual flow at 95 MW
**Stage 1 - Energy Prices at the RTO Border (Proxy Bus Prices)**

The proxy bus prices will be calculated for each stage of the congestion management example. These examples illustrate that the proxy bus prices will move in the same direction as the constrained bus prices when the M2M Flowgate is binding in both RTO security-constrained economic dispatches. The LMPs throughout both RTOs are equal to their System Marginal Price so long as the RTOs are unconstrained (no binding constraint resulting in redispatch of generation). This example also ignores marginal losses to simplify the illustration.
Stage 2 - Transmission Constraint Initialization

The RTO B (Monitoring RTO) dispatch software is projecting that the flow on Flowgate A is increasing and that *9 MW of flow relief* will be required. (Note: The 9 MW is derived from RTO B’s look-ahead dispatch software along with a parallel path evaluation). The security-constrained dispatch solution for RTO B results in both Generator 2 and Generator 3 being dispatched; the system marginal price for RTO B remains at $40/MWh. Generator 3 is the most cost effective unit to control the constraint.

The Flowgate A constraint shadow price for RTO B will be equal to:

\[
\frac{(\text{Gen 2 Offer Price} - \text{System Marginal Price for RTO B})}{\text{(Generator 2 GLDF on Constraint)}}
\]

\[
\frac{($60/MWh-40/MWh)}{-0.20} = -$100/MW of Flow Relief.\textsuperscript{4}
\]

\textsuperscript{4} The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 2 drives the constraint shadow price because it has the highest offer and the lowest GLDF.
The LMP for Gen 2 will be:

System Marginal Price for RTO B + (Gen 2 GLDF)(RTO B Shadow Price)

\[ \$40/\text{MWh} + (-.2)(-$100/\text{MWh flow relief}) = \$60/\text{MWh} \]

The LMP for Gen 3 will be:

System Marginal Price for RTO B + (Gen 3 GLDF)(RTO B Shadow Price)

\[ \$40/\text{MWh} + (-.3)(-$100/\text{MWh flow relief}) = \$70/\text{MWh} \]

The conditions for Stage 2, the initial transmission constrained scenario, are as follows:
**Stage 2 - Energy Prices at the RTO Border (Proxy Bus Prices)**

The proxy bus price for RTO A as calculated by RTO B will include the impact of the constraint on Flowgate A.

- Since the constraint is not binding in RTO A in Stage 2, the proxy price for RTO B as calculated by RTO A will remain at the system marginal price of RTO A.
- Since the proxy bus prices for each RTO reflect the value of imports or exports from the neighboring RTO, these proxy prices will be set by the system marginal price in the RTO that is calculating the proxy price.

RTO B’s Proxy price for RTO A is as follows:

\[
\text{System Marginal Price for RTO B} + (\text{Proxy bus GLDF})(\text{RTO B Shadow Price})
\]

\[
\text{System Marginal Price for RTO B} + (0.3)(-\text{\$100/MWh flow relief}) = \text{\$10/MWh}
\]

![Diagram of RTO A and RTO B with energy prices and flow information](image-url)
**Stage 3 – First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Monitoring RTO)**

- RTO B notifies RTO A of the transmission constraint Condition on Flowgate A. Initially RTO B requests RTO A to maintain its current market flow on Flowgate A. RTO B sends its latest shadow price of -$100/MWh to RTO A.

- RTO A enters the constraint into its security-constrained dispatch software with the current flow equal to the limit using -$100/MWh as its shadow price limit. (The current flow equals 35 MW in this case.) Since RTO A’s load is growing, the constraint binds with a shadow price less than the -$100/MWh limit. (Assume Firm Flow is 40 MW.)

Flowgate A constraint shadow price for RTO A will be equal to:

\[
\frac{(\text{Gen 1 Offer Price} - \text{System Marginal Price for RTO A})}{\text{(Gen 1 GLDF on Constraint)}}
\]

\[
\frac{($20/MWh -$35/MWh)}{0.30} = -$50/MW of Flow Relief. \text{\,}^5
\]

The LMP for Gen 1 will be:

\[
\text{System Marginal Price for RTO A} + (\text{Gen 1 GLDF})(\text{RTO A Shadow Price})
\]

\[
$35/MWh + (0.3)(-$50/MWh flow relief) = $20/MWh
\]

---

\text{\,}^5 The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 2 drives the constraint shadow price because it has the highest offer and the lowest GLDF. The resulting shadow price of -$50/MWh is less than the limit of -$100/MWh from the Monitoring RTO A.
Stage 3 - Energy Prices at the RTO Border (Proxy Bus Prices)

The proxy bus price for RTO A as calculated by RTO B, will include the impact of the constraint on Flowgate A. Since the constraint is now binding in RTO A in stage 3, the proxy price for RTO B as calculated by RTO A will include impact of the constraint on Flowgate A.

RTO A’s Proxy price for RTO B is as follows:

System Marginal Price for RTO A + (Proxy bus GLDF)(Shadow Price)

\[ \text{System Marginal Price for RTO A} + (-.3)(-\$50/MWh flow relief) = \$50/MWh \]
RTO B analyzes the constraint shadow price information and determines that RTO A has a more economical alternative to provide the Flow Relief than is currently being obtained by operating Generator 2 out of merit. The analysis results in RTO B requesting RTO A to provide 4 MW more of Flow Relief to enable Generator 2 to come offline.

RTO A is able to reduce its market flow on Flowgate A to the desired 31 MW limit in its dispatch software. RTO A can achieve the requested relief by lowering Gen 1 while observing the shadow price limit from RTO B.

After the flow on Flowgate A is reduced by the redispatch action from RTO A, RTO B requests Generator 2 to come off-line, because it will no longer be required to control the Flowgate A limit.

The Flowgate A constraint shadow price for RTO B will be equal to:
The LMP for Gen 2 will be:

System Marginal Price for RTO B + (Gen 2 GLDF)(RTO B Shadow Price)

\[ \$40/MWh + (.2)(-\$60/MWh \text{ flow relief}) = \$52/MWh \]

The LMP for Gen 3 will be:

System Marginal Price for RTO B + (Gen 3 GLDF)(RTO B Shadow Price)

\[ \$40/MWh + (.3)(-\$60/MWh \text{ flow relief}) = \$58/MWh \]

---

6 The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 3 drives the constraint shadow price because it is the only unit online for the constraint.
The conditions for Stage 4 are as follows:

**RTO A**
System Marginal Price = $35/MWh

**Gen 1 (under RTO A)**
Offer Price = $20/MWh
GLDF = 30%
LMP = $20/MWh

**Flowgate A**

**RTO B**
System Marginal Price = $40/MWh

Flow = 95 MW, Limit = 100 MW

**RTO B Shadow price** = $60/MWh

**RTO A Shadow price** = -$80/MWh

**Gen 3 (under RTO B)**
Offer Price = $58/MWh
GLDF = -30%
LMP = $58/MWh

**Gen 2 (under RTO B)**
Offer Price = $60/MWh
GLDF = -20%
LMP = $52/MWh
**Stage 4 - Energy Prices at the RTO Border (Proxy Bus Prices)**

The proxy bus price for RTO A, as calculated by RTO B, will include the impact of the constraint on Flowgate A. Since the constraint remains binding in RTO A in Stage 4, the proxy price for RTO B as calculated by RTO A will include impact of the constraint on Flowgate A.

RTO B’s Proxy price for RTO A is as follows:

**System Marginal Price for RTO B + (Proxy bus GLDF)(RTO B Shadow Price)**

\[ \$40/\text{MWh} + (0.3)(-\$60/\text{MWh flow relief}) = \$22/\text{MWh} \]
**Stage 5 – Ongoing Coordinated Dispatch Cycles**

As the constrained operations progress, the RTOs will periodically verify that the constrained operations are coordinated by ensuring that the constraint shadow prices are reasonably close for the given constrained scenario.

In this case, the RTO A shadow price is $50/MWh and the RTO B shadow price is $60/MWh, which indicates that the system is optimally coordinated for the given constrained condition.

The RTO B’s proxy bus price for RTO A is $22/MWh which is very close to the LMP at Gen 1 bus ($20/MWh) in RTO A. The RTO B’s proxy bus for RTO A and the Gen 1 bus both have +30% GLDF on Flowgate A. One of the objectives of the market-to-market coordination is to achieve price convergence for buses with similar GLDFs across the RTO border. Similarly, the RTO A’s proxy bus price for RTO B is $50/MWh which is reasonably close to the LMP at Gen 3 bus ($58/MWh) in RTO B. The RTO A’s proxy bus for RTO B and the Gen 3 bus both have -30% GLDF on Flowgate A.

**Settlement calculations**

Stages 4 and 5 are the steady state situation integrated over an hour.

Firm Flow Entitlement for RTO A on Flowgate A per the example = 40MW

Real-Time Market Flow MW by RTO A on Flowgate A = 31MW (requested by RTO B)

RTO A Shadow Price on Flowgate A = -$50/MWh

\[
\text{Payment (RTO B to RTO A)} = ((\text{Firm Flow Entitlement MW} + \text{Approved MW}) - \text{Real-Time Market Flow MW}) \times \text{Transmission Constraint Shadow Price in Non-Monitoring RTOs Dispatch Solution}
\]

\[
\text{Payment (RTO B to RTO A)} = ((40/MWh + 0) - 31/MWh) \times -$50/MWh
\]

\[
\text{Payment (RTO B to RTO A)} = $450
\]

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When One of the RTOs Does Not Have Sufficient Redispatch

Under the normal market-to-market implementation, sufficient redispatch for a M2M Flowgate may be available in one RTO but not the other. When this condition occurs, in order to ensure a physically feasible dispatch solution is achieved, the RTO without sufficient redispatch will activate logic in its dispatch algorithm which redispatches all available generation in the RTO to control the M2M Flowgate to a “relaxed” limit. Then this RTO calculates the shadow price for the M2M Flowgate using the available redispatch which is limited by the maximum physical control action inside the RTO. Because the magnitude of the shadow price in this RTO cannot reach that of the other RTO with sufficient redispatch, unless further action is taken, there will be a divergence in shadow prices and the LMPs at the RTO border.

The example below illustrates how the LMPs at the RTO border diverge under this condition:

The LMPs differ by $24 even though Bus A and Bus B are electrically close to each other.
A special process is designed to enhance the price convergence under this condition. If the Non-Monitoring RTO cannot provide sufficient relief to reach the shadow price of the Monitoring RTO, the constraint relaxation logic will be deactivated. The Non-Monitoring RTO will then be able to use the Monitoring RTO’s shadow price without limiting the shadow price to the maximum shadow price associated with a physical control action inside the Non-Monitoring RTO. With the M2M Flowgate shadow prices being the same in both RTOs, their resulting bus LMPs will converge in a consistent price profile.

The following example illustrates how the price convergence can occur:

Bus A & Bus B have the same impact on RCF Z (4% lower help)

Monitoring RTO (MRTO)
- Shadow Price for RCF Z = 800
- MRTO system price = 50
- LMP at Bus A = 50 + (800)*(-0.04)
  = 18

Non-Monitoring RTO (NMRT)
- Shadow Price for RCF Z = 800
  (With the constraint relaxation logic deactivated, the NMRT will be able to use the MRTO’s shadow price without limiting the shadow price to the maximum shadow price associated with a physical control action inside the NMRT)
- NMRT system price = 50 (same as MRTO)
- LMP at Bus B = 50 + (800)*(-0.04)
  = 18

The LMPs converge to $18 for Bus A and Bus B.

This process also allows price convergence when the Non-Monitoring RTO has a higher shadow price than the Monitoring RTO.

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Section 8 Appropriate Use of the Market-to-Market Process Version: 0.0.0

Effective: 6/16/2011

8 Appropriate Use of the Market-to-Market Process

Under normal operating conditions, the Midwest ISO and PJM operators will model all Reciprocal Coordinated Flowgates (RCFs) in their respective EMSs. A subset of these Flowgates, impacted by market flows from the two RTOs’ energy markets, will be subject to the market-to-market process and called M2M Flowgates. This subset will be controlled using market-to-market tools for coordinated redispatch and additionally will be eligible for market-to-market settlements.

In principle and as much as practicable, Parties agree that the goal is to control to the most limiting Flowgate using the actual Flowgate limit. The RTOs will record and exchange actual M2M Flowgate limits, the limit used to bind, and a reason for significant deviation.

There are times when either Party, acting as the Monitoring RTO, will bind a M2M Flowgate different from its actual limit. The Parties have agreed in subsections 8.1 through 8.4 of this Section 8 to the conditions under which market-to-market settlement will occur even though a limit to which the Monitoring RTO is binding (limit control) is less than its actual limit.

8.1 Qualifying Conditions for M2M Settlement:

8.1.1 Purpose of Market-to-Market. Market-to-market was established to address regional, not local issues. The intent is to implement market-to-market coordination and settle on such coordination where both Parties have significant impact.

8.1.2 Minimizing Less than Optimal Dispatch. The Parties agree that, as a general matter, they should minimize financial harm to one RTO that results from market-to-market coordination initiated by the other RTO that produces less than optimal dispatch, which can lead to revenue inadequacy for FTRs, and impose the burden for such revenue inadequacy on one or both RTOs.

8.1.3 Use Market-to-Market Whenever Binding a M2M Flowgate. The market-to-market process will be initiated by the Monitoring RTO whenever an M2M Flowgate is constrained and therefore binding in its dispatch.

8.1.4 Most Limiting Flowgate. Generally, controlling to the most limiting Flowgate provides the preferable operational and financial outcome. In principle and as much as practicable, market-to-market coordination will take place on the most limiting Flowgate, and to that Flowgate’s actual limit (thermal, reactive, stability).
a. Market-to-market events that involve the use of a limit control that is below 95% of the actual limit will be subject to an after-the-fact review, unless the lower limit was agreed to by the RTOs prior to the market-to-market binding event. The review will determine if normal market-to-market settlements are appropriate. If market-to-market settlements are determined by the Parties not to be appropriate, then settlements will not occur on the M2M Flowgate. Sufficient real-time and after-the-fact data will be exchanged to enable these reviews. The Parties may agree to change the trigger for review to a lower number for specific Flowgates, however, either Party may request review of specific instances that are bound above the established binding percentage.

8.1.5 Substitute Flowgates. The Parties agree that, if the use of substitute Flowgates is minimized and the ability to coordinate on the most limiting Flowgate in the very near term is enabled, there should be very few instances where market-to-market coordination occurs without resulting settlement.

a. Generally, market-to-market coordination without the normal market-to-market settlement will be limited to times when: (1) a substitute is used for a period in excess of that defined in Section 8.1.5 (b) (ii) below, or (2) a substitute Flowgate (whether M2M or non-M2M) is used and the most limiting Flowgate is later determined to fail the market-to-market tests.

b. Where the most limiting constraint (monitored/contingent element pair) is not a defined M2M Flowgate:

i. Parties will add the Flowgate definition and activate market-to-market coordination on that Flowgate (as opposed to a substitute) as soon as reasonably practicable; or

ii. A substitute Flowgate may be used for a short time (generally less than an hour) until it is possible to coordinate using the most limiting Flowgate. Parties will attempt to use either: (i) the most limiting M2M Flowgate or (ii) the most limiting Flowgate that is modeled by both Parties, in that order of preference. If possible, the Parties should use another Flowgate that is limiting. Optimal choices are Flowgates with the same or very similar Market Flow impacts (sensitivities) resulting in a very similar redispatch and market-to-market settlement.

c. A substitute Flowgate can be used in the market-to-market process pending the outcome of the coordinated Flowgate tests. The substitute Flowgate will be utilized only until the actual constraint can be entered in both the Monitoring and Non-Monitoring RTO systems as an M2M Flowgate. Market-to-market settlement is dependent on the outcome of the coordinated Flowgate tests on the actual constraint and the RTO.
requesting the use of a substitute Flowgate will do so at its own risk that
market-to-market settlement may not occur.

d. A substitute M2M Flowgate will not be used to control for another
constrained M2M Flowgate except in very limited circumstances and only
where there is prior mutual agreement between Midwest ISO and PJM to
do so. Mutual agreement is established only when it has been
communicated and logged by the control center operators that the
coordinated Flowgate is not the most limiting (i.e., it is a substitute
Flowgate).

e. A substitute M2M Flowgate will not be used to control for a non-M2M
Flowgate that has failed the Flowgate study or has not been entered into
the study process.

f. Any use of substitute Flowgate should be clearly logged by both RTO
operators with the actual start time, the actual end time and the reason for
using a substitute Flowgate.

g. If the Monitoring RTO requests TLR on an M2M Flowgate but has not
initiated the market-to-market process and is not binding its market for
that Flowgate, the Non-Monitoring RTO is not required to bind its market
for that Flowgate in order to meet the Non-Monitoring RTO’s TLR relief
obligation. It will be assumed that the Monitoring RTO is binding its
market for the actual constraint and that the actual constraint is already
active in the market-to-market process (if the actual constraint is an M2M
Flowgate).

8.1.6 Operating Guides that refer to market-to-market operation do so under the
assumption that the Flowgates for which market-to-market operations take place are,
or are expected to be, constrained. Operating Guides are written by operators and are
not intended to result in settlement not otherwise contemplated by the JOA or this
ICP. Safe Operating Mode (SOM) is reserved for abnormal conditions when existing
operating guides and normal tool sets are not sufficient to manage abnormal operating
conditions. After declaring SOM, operator actions may include using market-to-
market tools in addition to direct dispatch. Operators may choose to use substitute
M2M Flowgates with the dispatch tools to maintain reliable operations. Settlement
determination will occur during the After-the-Fact Review set forth in Section 8.4
below. Generally, settlement for market-to-market coordination that takes place after
SOM is declared will apply if the settlement would apply under normal conditions.

8.2 Specific Conditions Applicable to Section 8.1.4 (Most Limiting Flowgate)

8.2.1 Market-to-Market Events Not Requiring an After-the-Fact Review
The Midwest ISO and PJM operators will model all M2M Flowgates facilities with actual limits in their respective EMSs. The Midwest ISO EMS model uses design thermal limits of equipment. The Midwest ISO limits are updated in UDS following contacts with Transmission Owners prior to binding. The Midwest ISO and PJM operators will control the flows on these M2M Flowgates in their respective UDSs at a binding percentage that is 95% or greater of the M2M Flowgate actual limit.

8.2.2 Market-to-Market Events Requiring an After-the-Fact Review

All M2M events that involve the use of a limit control that is below 95% of the actual limit will be subject to an after-the-fact review to determine whether this was an appropriate use of the market-to-market process and is subject to normal market-to-market settlement. The following criteria will be used in making such a determination:

8.2.2.1 Reducing the UDS Binding Percentage to Provide Necessary Constraint Control:

a. A reduced UDS binding percentage below 95% of the actual facility limit can be applied to an M2M Flowgate by the Monitoring RTO provided the monitored element (for the defined contingency condition) of the M2M Flowgate meets the following conditions:

i. The monitored element is, or is expected to be, over its actual limit (post contingency if applicable) and the UDSs are not providing the desired relief.

ii. Transient system behavior necessitates controlling the M2M Flowgate to a target between 95% and 100% and providing some margin. To achieve this, in some instances, the UDS percentage may need to be below 95%.

iii. The limit for the monitored element changes due to equipment switching out of service. For instance the actual limit of a line is reduced when one of the breakers in a breaker-and-half configuration is out of service, or only one parallel transformer remains in service at one of the line end terminals.

iv. A constraint with a very high loading volatility such that loading is expected to exceed 100% of the actual limit, even when the UDS binding percentage is significantly below that value.

b. The reduced UDS binding percentage should only be applied for the time duration necessary to manage the initiating condition and shall be returned to normal as soon as possible.

c. Each time the Monitoring RTO reduces the binding limit control of an M2M Flowgate below 95% for an actual or relevant post contingency overload, the Monitoring RTO operator will make a best effort to notify the Non-Monitoring RTO operator of the new limit control, the reason for the change.
and when the limit control is expected to be returned to normal (if known). Both RTO operators will log the event. This notification only applies to an operating condition causing a limit control change; it does not apply to the use of temperature adjusted limits, voltage limits or stability limits implemented as flow limits.

i. A limit reported by a Transmission Owner on the operating day shall require an accompanying reason. If the limit is set to control for underlying facilities, this shall be called out specifically. Any reason other than those specifically called out herein shall be reported.

d. The Monitoring RTO will operate to the most conservative limit when there are conflicting results between two different EMSs (either another RTO EMS or a Transmission Owner EMS) unless the reason for the difference is known.

8.2.2.2 Reducing the UDS Binding Percentage of a M2M Flowgate for Prepositioning

a. In some conditions system flows are expected to change quickly due to load pick-up, planned, and emergency outages, and the UDS may not be accurately predicting a resulting overload on the M2M Flowgate in the near future. When a reduction in binding percentage is initiated by the operator to mitigate expected impacts on an M2M Flowgate from a planned outage, that action shall be taken to prepare the system consistent with the time submitted on the outage ticket or as revised by the equipment operator. This reduction should be for as short a time as practicable but may be extended if the outage is delayed. If possible, initiating the reduction in binding percentage shall be delayed until the outage begins.

b. M2M Flowgates may be de-rated for a short period of time to pre-position the system for an expected change. These expected changes can include:

i. Change in unit status (anticipated as part of an upcoming outage, reacting to an imminent emergency outage, or change in commitment if the unit for which the commitment was changed cannot be adequately ramped to allow normal redispatch to manage any resulting constraints).

ii. Transmission system topology change (either anticipated event or as part of an upcoming planned outage). In this case, every effort shall be made to add the expected constraint to the systems and bind on the expected constraint instead of using a substitute Flowgate.

iii. Increase or decrease in wind generation output.

c. Reducing the limit to pre-position the system will be considered an appropriate use of market-to-market tools but subject to settlement adjustment for substitute M2M Flowgates applying a hold harmless approach discussed in
the After the Fact Review process set forth in Section 8.4 below. The time duration of such events shall be limited to that necessary to pre-position to avoid excessive impacts on market prices.

8.3 Specific Conditions Applicable to Section 8.1.6 (Operating Guides)

8.3.1 All op guides are subject to review by Midwest ISO and PJM through which either RTO can request removal of a reference to the market-to-market process. Where reference to the market-to-market process has been removed and not replaced by alternate congestion management actions, the use of SOM will be added to the op guide if it is not already included in the op guide. Before modifying existing op guides, one of the following conditions must be met:

a. One or more constraints are made available to assist in managing West-to-East flows across NIPS to avoid the conditions that prompted SOM; or

b. Midwest ISO and PJM will agree to a mechanism to manage congestion that will avoid the need for repeated SOM declarations on the same constraint.

8.3.2 In the event of severe abnormal system conditions, such as storm damage to critical facilities, the Inter-RTO Steering Committee shall meet as soon as practicable to agree upon the response, which shall be incorporated into a temporary operating guide.

8.4 After-the-Fact Review to Determine Market-to-Market Settlement

8.4.1 Based on the communication and data exchange that has occurred in real-time between the Monitoring RTO operator and the Non-Monitoring RTO operator, there will be an opportunity to review the limit change and the use of the market-to-market process to verify it was an appropriate use of the market-to-market process and subject to market-to-market settlement. The Monitoring RTO will initiate the review as necessary to apply these conditions and settlements adjustments.

a. A review will verify that the limit used in the market-to-market coordination represented the actual limit of the monitored element of the original Flowgate that has passed one of the M2M Flowgate Studies. The Monitoring RTO will archive and make available data (including all UDS solutions) that supports the decision to change the M2M Flowgate limit. The Parties will mutually agree upon, and document in writing and post on the Parties’ websites, the data that should be exchanged and/or archived to meet this requirement, and shall retain the data for the period applicable to other data used to audit settlements inputs and market flow calculations under this agreement.

b. A review will verify the outcome of the M2M Flowgate Studies and whether the potential Flowgate passed one of the M2M Flowgate Studies by both the
Monitoring RTO and the Non-Monitoring RTO. The Monitoring RTO uses market-to-market tools before a M2M Flowgate is approved at its own risk regarding market-to-market settlement. After the M2M Flowgate Studies are complete, if the Flowgate did not pass at least one of the studies conducted by the Monitoring RTO and at least one of the studies conducted by the Non-Monitoring RTO, then settlements will be adjusted as follows.

i. If the Non-Monitoring RTO’s integrated market flows are below its Firm Flow Entitlement for the hour, there will be a normal market-to-market settlement with a payment from the Monitoring RTO to the Non-Monitoring RTO for the hour.

ii. If the Non-Monitoring RTO’s integrated market flows exceed its Firm Flow Entitlement for the hour, there will be no market-to-market settlement for the hour.

iii. If the Monitoring RTO was requested to initiate the market-to-market process on the Monitoring RTO’s Flowgate to assist the Non-Monitoring RTO, the Monitoring RTO will be held harmless as follows.

a. If the Non-Monitoring RTO’s integrated market flows are below its Firm Flow Entitlement for the hour, there will be no market-to-market settlement for the hour.

b. If the Non-Monitoring RTO’s integrated market flows exceed its Firm Flow Entitlement for the hour, there will be a normal market-to-market settlement with a payment from the Non-Monitoring RTO to the Monitoring RTO for the hour.

8.4.2 The Non-Monitoring RTO may request the Monitoring RTO to implement the market-to-market process on its behalf. There will be an after the fact review performed to determine whether this market-to-market event should be subject to settlement. If the review finds it is subject to settlement, the usual criteria will be applied. If the review finds it is not subject to settlement, the usual criteria will be applied except that the Monitoring RTO shall be held harmless.

a. If the Non-Monitoring RTO’s integrated market flows are below its Firm Flow Entitlement for the hour, there will be no market-to-market settlement for the hour.

b. If the Non-Monitoring RTO’s integrated market flows exceed its Firm Flow Entitlement for the hour, there will be a normal market-to-market settlement with a payment from the Non-Monitoring RTO to the Monitoring RTO for the hour.

8.5 M2M Data Exchange
8.5.1 A data exchange will be established. Parties shall mutually agree upon data, format and frequency of exchanges. The data exchange must be updated to include the following data as soon as practicable if requested by either Party.

a. actual Flowgate SE/SA flow from the approved case,
b. UDS solution %,
c. operator entered binding %,
d. actual Flowgate limit, and
e. shadow price.

Effective Date: 6/16/2011 - Docket #: ER11-3979-000
Appendix A Definitions Version: 0.0.0 Effective: 6/16/2011

### Appendix A: Definitions

Any undefined, capitalized terms used in this ICP shall have the meaning: (i) provided in the Joint Operating Agreement between PJM and Midwest ISO, or in the CMP, or (ii) given under industry custom and, where applicable, in accordance with good utility practices.

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Monitoring RTO</td>
<td>The RTO that has the primary responsibility for monitoring and control of a specified M2M Flowgate</td>
</tr>
<tr>
<td>Non-Monitoring RTO</td>
<td>The RTO that does not have the primary responsibility for monitoring and control of a specified M2M Flowgate, but does have generation that impacts that Flowgate</td>
</tr>
<tr>
<td>Firm Flow</td>
<td>The estimated impacts of firm Network and Point-to-Point service on a particular M2M Flowgate.</td>
</tr>
<tr>
<td>Firm Flow Entitlement</td>
<td>The firm flow entitlement (FFE) represents the net allocation on M2M Flowgates used in the market-to-market settlement process. The FFE is determined by taking the forward allocation (using 0% allocations) and reducing it by the lesser of the two day-ahead allocation in the reverse direction (using 0% allocations) or the generation-to-load impacts in the reverse direction (down to 0%). The generation-to-load impacts in the reverse direction come from the day-ahead allocation run. The forward allocation comes from the day-ahead network and native load (DA NNL) calculation. The FFE may be positive, negative or zero.</td>
</tr>
<tr>
<td>Flow Relief</td>
<td>The reduction in the MW flow on an M2M Flowgate that is caused by the generation redispatch as a result of the binding transmission constraint</td>
</tr>
<tr>
<td>Market Flow</td>
<td>The flow in MW on an M2M Flowgate that is caused by all generation deliveries to load in the RTO footprint.</td>
</tr>
<tr>
<td>Reciprocal Coordinated Flowgate (RCF)</td>
<td>A Coordinated Flowgate for which Reciprocal Entities have generation that has a GLDF on the flowgate at or above the NERC approved threshold (currently, 5% or greater)</td>
</tr>
<tr>
<td>Requesting RTO</td>
<td>RTO that is requesting an increase in their Firm Flow Entitlement in the Day-Ahead energy market coordination procedures. A Requesting RTO may be a Monitoring RTO or a Non-Monitoring RTO with respect to a given RCF in Real Time.</td>
</tr>
</tbody>
</table>
Responding RTO: RTO that is responding to a request to reduce their Firm Flow Entitlement in the Day-Ahead energy market coordination procedures. A Responding RTO may be a Monitoring RTO or a Non-Monitoring RTO with respect to a given RCF in Real Time.

UDS: Security constrained, economic dispatch software used to determine dispatch instructions to resources in a Party’s market area.

M2M Flowgate: Has the definition as defined in Section 1 of this Attachment 3.

M2M Flowgate Studies: M2M Flowgate Studies consist of the coordinated flowgate tests defined in Section 3.2.1 of the Congestion Management Process and the significantly impacted flowgate tests defined in Section 1.1.3 of this Attachment 3.

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ATTACHMENT 4 CROSS-BORDER GRANDFATHERED PROJECTS Version: 0.0.0

Effective: 9/17/2010

ATTACHMENT 4

CROSS-BORDER GRANDFATHERED PROJECTS

Arrowhead – Gardner Park 345 kV Line

AEP 765 kV Cloverdale Line

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
ATTACHMENT 5 EMERGENCY ENERGY TRANSFERS Version: 0.0.0 Effective: 9/17/2010

ATTACHMENT 5

EMERGENCY ENERGY TRANSACTIONS

PJM or the Midwest ISO may, from time to time, have insufficient Operating Reserves available to their respective systems, or need to supplement available resources to cover sudden and unforeseen circumstances such as loss of equipment or forecast errors. Such conditions could result in the need by the Party experiencing the deficiency to purchase Emergency Energy for Reliability reasons.

The purpose of this Attachment 5 is to allow for the exchange of Emergency Energy between the Parties during such times when resources are insufficient and commercial remedies are not available. The offer to provide Emergency Energy shall be available only when the Party experiencing the deficiency has declared an Energy Emergency Alert, Level Alert 2, as defined in Attachment 1 of NERC Standard EOP-002-0, or as defined in a subsequent revision of such Standard.

1.0: CHARACTERISTICS OF THE POWER AND ENERGY

Unless otherwise mutually agreed, all power and energy made available by the delivering Party shall be three phase, 60 Hz alternating current at operating voltages established at the Delivery Point in accordance with system requirements and appropriate to the Interconnection.

2.0: NATURE OF SERVICE

2.1 PJM, to the maximum extent it deems consistent with:

(a) the safe and proper operation of its own system,
(b) the furnishing of dependable and satisfactory services to its own customers, and
(c) its obligations to other parties,

shall make available to the Midwest ISO energy market Emergency Energy from available generating capability in excess of its load requirements up to the transfer limits in use between the two Balancing Authority Areas.

PJM shall refer to all Emergency Energy transactions as being sold:

(a) “Recallable” where such a delivery could reasonably be expected to be recalled if
PJM needed the generation for a deployment of reserves or other system Emergency; or

(b) “Non-Recallable” where PJM would normally be able to continue delivering the Emergency Energy following a reserve deployment.

The Parties shall use reasonable efforts to ensure that an Emergency Energy transaction continues only until it can be replaced by a commercial transaction.

2.2 The Midwest ISO, to the maximum extent it deems consistent with:

(a) the safe and proper operation of its own Transmission System,
(b) the furnishing of dependable and satisfactory services to its own customers, and
(c) its obligations to other parties, including the terms and conditions of the Midwest ISO Tariff.

shall make available to PJM Emergency Energy from available generating capability in excess of its load requirements up to the transfer limits in use between the two Balancing Authority Areas.

The Midwest ISO shall refer to all Emergency Energy transactions as being sold:

(a) “Recallable” where such a delivery could reasonably be expected to be recalled if the Midwest ISO needed the generation for a deployment of reserves or other system Emergency; or

(b) “Non-Recallable” where the Midwest ISO would normally be able to continue delivering the Emergency Energy following a reserve deployment.

The Parties shall use reasonable efforts to ensure that an Emergency Energy transaction continues only until it can be replaced by a commercial transaction.

2.3 In the event one Party is unable to provide Emergency Energy to the other Party when needed, but there is energy available from a third party Balancing Authority, delivery of such Emergency Energy will be facilitated to the extent feasible.

2.4 Midwest ISO does not take title to energy, or Emergency Energy, under its tariff but will purchase or sell such energy for and on behalf of, its Market Participants and will invoice and make payment to PJM, as set forth in the Joint Operating Agreement.
3.0: RATES AND CHARGES

3.1 All Emergency Energy transactions shall be billed based on scheduled deliveries.

3.2 All rates and charges associated with Emergency Energy shall be expressed in funds of the United States of America.

3.3 Midwest ISO and PJM agree that the charge for Emergency Energy delivered by one Party to the other Party shall be as defined below.

The delivering Party shall be allowed to include, in the total price charged for Emergency Energy, all costs incurred in the delivery of Emergency Energy to the Delivery Point, and the receiving Party shall be responsible for all costs at and beyond the Delivery Point.

Direct Transaction

The charge for Emergency Energy supplied by delivering Party in any hour to the receiving Party shall be calculated using the following two-part formula. The first part of the formula calculates the energy portion of the charge and the second part incorporates any transmission charges incurred by the delivering Party to deliver the Emergency Energy to the Delivery Point. In the case of PJM as the delivering Party, the cost of the energy portion shall be the greater of 150% of any applicable Locational Marginal Price (“LMP”) at the point(s) of delivery to provide the Emergency Energy, or $100/MWHr. In the case of the Midwest ISO as the delivering Party, the cost of the energy portion shall be the greater of 150% of the LMP at the point(s) of exit at the bus or buses at the border of the delivering Party’s market, or $100/MWHr.

Energy Portion for an hour = 

\[
\text{(Emergency Energy supplied in the hour in MWHr) times (delivering Party’s cost of such energy in $/MWHr)}
\]

Transmission Charge to Delivery Point (if applicable) =

\[
The actual ancillary services (including delivering Party’s market charges applicable to export schedules) and transmission costs incurred by the delivering Party in delivering such Emergency Energy to the Delivery Point pursuant to the delivering Party’s Tariff or the equivalent thereof.
\]

Total Charge for Emergency Energy supplied in any hour =

\[
The sum of the Energy Portion for an hour and the Transmission Charge for that same hour.
\]

A Party requesting Emergency Energy under this Section is obligated to pay for the Emergency Energy in the amount requested, times a minimum period of one clock hour.
once the delivering Party has initiated the redispatch of generation in the delivering Party’s energy market or dispatch order, so that the energy will be made available at the time requested to the receiving Party at the Delivery Point.

Transaction from Third Party Supplier

The charge for Emergency Energy supplied to the receiving Party from a third party through the delivering Party’s system shall be calculated using the following two-part formula. The first part of the formula calculates the energy portion of the charge and the second part incorporates any transmission charges incurred by the delivering Party to deliver the Emergency Energy to the Delivery Point. The delivering Party’s cost for Emergency Energy shall be the cost that the third-party supplier charges the delivering Party or as otherwise stated in an agreement between receiving Party and the third-party supplier.

**Energy Portion for an hour =**

\[(\text{Emergency Energy supplied in the hour in MWhr}) \times (\text{Third-party Supplier’s charge for such energy in $/MWhr})\]

**Transmission Charge to Delivery Point (if applicable) =**

*The actual ancillary service costs (as applicable), transmission costs and all other applicable costs attributable to such transactions incurred by the delivering Party in delivering such energy to the Delivery Point pursuant to the delivering Party’s Tariff or the equivalent thereof.*

**Total Charge for Emergency Energy supplied in an hour =**

*The sum of the energy portion for an hour and the transmission charge for that same hour.*

A Party requesting Emergency Energy under this Attachment 5 is obligated to pay the Transmission Charge, times a minimum period of one clock hour, once the delivering Party has entered the necessary schedules in the delivering Party’s system.
4.0: MEASUREMENT OF ENERGY INTERCHANGED

All Emergency Energy supplied at the Delivery Point shall be metered. The delivering Party shall be responsible for the actual losses as a result of delivery to the delivery Point and the receiving Party shall be responsible for all losses from the delivery Point.

5.0: BILLING AND PAYMENT

5.1. Billing for, and payment of, all charges incurred pursuant to this Attachment 5 shall be pursuant to Section 16.2 of the Joint Operating Agreement of which this Attachment is a part.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
TAB A-2

Redlined Version of Revised JOA Provisions
**Section 9.1 Administration; Committees**

**Version:** 1.0.0

**Effective:** 1/1/2014

9.1 Administration; Committees.

9.1.1 Joint RTO Planning Committee.

The ISC shall form, as a subcommittee, a Joint RTO Planning Committee (JRPC), comprised of representatives of the Parties’ respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, every other year, to designate a Chairman of the JRPC to serve a one-year calendar term, except that the term of the first Chairman shall commence on the Effective Date and end December 31, 2004. The ISC shall designate the first Chairman. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings.

The JRPC shall coordinate the coordinated system planning under this Agreement, including the following:

For the purpose of coordinated system planning, the JRPC shall meet no less than twice per year. The JRPC may meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

9.1.1.1 JRPC Responsibilities

The JRPC is the decision making body for coordinated system planning. The Interregional Planning Stakeholder Advisory Committee (IPSAC) and other stakeholder groups may provide input to the JRPC.

Responsibilities of the JRPC include the following:

(a) On an annual basis the JRPC shall conduct a review of identified transmission issues in accordance with section 9.3.5.2.a of this Agreement.

(b) The JRPC, with input from the IPSAC, shall determine if a Coordinated System Plan study should be performed. If yes, such study shall be performed in accordance with section 9.3.5.2.b.

(c) Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed to by the Parties, the JRPC shall develop common power system analysis models to perform coordinated system planning, as well as models for power flow analyses, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the Parties, the JRPC will direct the performance of a detailed review of the appropriateness of applicable power system models.
Prepare, on a regular basis, a Coordinated System Plan as required under Section 9.3.5.

Coordinate all planning activities under this Article IX, including the exchange of data under this Article.

Maintain an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process.

Meet at least semi-annually to review and coordinate transmission planning activities. Such meetings shall include, as determined by either party to be necessary based on internal discussions, discussion of any system operations or market operations issues as they impact long range planning and the coordination of planning between the systems.

Support the review by any federal or provincial agency of elements of the Coordinated System Plan.

Support the review by multi-state entities to facilitate the addition of interstate transmission facilities.

Establish working groups as necessary to provide adequate review and development of the regional plans.

Establish a schedule for the rotation of responsibility for data management, coordination of stakeholder meetings, coordination of analysis activities, report preparation, and other activities.

9.1.1.2 Participating in Multi-Party Studies

The JRPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under other joint agreements to which a Party is a signatory, for the purpose of providing for broader and more effective inter-regional planning coordination.

9.1.1.3 Coordinated System Planning Website

Each Party shall host its own website for communication of information related to interregional transmission coordination procedures. Under its direction, the JRPC shall coordinate with the Parties to ensure that all information and documents posted on each Party’s respective website is accurate and consistent. Each Party’s website shall contain.
at a minimum, the following information:

(a) Link to this Joint Operating Agreement
(b) Notice of scheduled IPSAC meetings
(c) Links to materials for IPSAC meetings
(d) Documents relating to Coordinated System Plan studies

9.1.2 Interregional Planning Stakeholder Advisory Committee.
The Parties shall form an IPSAC, in which participation is open to all stakeholders. The IPSAC shall facilitate stakeholder review and input into coordinated system planning with respect to the development of the Coordinated System Plan. IPSAC meetings shall be facilitated by the JRPC. IPSAC members shall consist of the stakeholder participants in joint stakeholder meetings called by the JRPC for the purpose of addressing issues under the responsibility of the JRPC as established by this Article IX. The IPSAC will meet no less frequently than prior to the start of each cycle of the coordinated planning process, during the development of the Coordinated System Plan, and upon completion of the plan to review final results.

For the purpose of coordinated system planning, the IPSAC shall meet no less than once per year. The IPSAC may meet more frequently during the development of a Coordinated System Plan study as determined to be necessary by the Parties. The JRPC shall meet annually with the IPSAC to review identified transmission issues and provide input on whether a Coordinated System Plan study should be performed. IPSAC meetings shall be on a mutually agreed to date determined by the JRPC.

The IPSAC will provide input to the JRPC on whether a Coordinated System Plan study should be performed pursuant to Section 9.3.5.2.a. If it is determined by the JRPC that a study should be performed, the IPSAC will provide input to the JRPC during the performance of the Coordinated System Plan study pursuant to Section 9.3.5.2.b.

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Section 9.2 Data and Information Exchange Version: 1.0.0 Effective:

1/1/2014 9/17/2010

9.2 Data and Information Exchange.

9.2.1 Annual Data and Information Exchange Requirement

In support of interregional coordinated system-planning coordination, each Party shall provide the other with the following data and information on an annual basis and will follow the stipulations for such exchange as noted below.
1. Power flow models for projected system conditions for the planning horizon (up to the next ten (10) years) that include planned generation development and retirements, planned transmission facilities and seasonal load projections.

2. System stability models with detailed dynamic modeling of generators and other active elements.

3. Production cost models for projected system conditions for the planning horizon that include generation and load forecasts and planned transmission facilities.

4. Assumptions used in development of above power flow, stability and production cost models.

5. Contingency lists for use in power flow, stability, and production cost analyses.

Models provided will be consistent with those used in the respective Party’s planning processes. Formats for the exchange of data will be agreed upon by the Parties from time to time. Parties can provide the best available information and will not be required to develop unique models to meet the requirements of this Agreement. Data compiled through other multi-regional modeling efforts can be used to meet the data exchange requirements of this Agreement as agreed to in writing by both Parties. This annual data exchange will be completed during the first quarter of the calendar year, unless Parties agree in writing to a different timeline.

9.2.2 Data and Information Exchange upon Request

In addition to the data and information specified in Section 9.2.1, each Party shall provide the other with the following data and information upon request. Unless otherwise indicated, such data and information shall be provided as requested by either Party, party and as available, within 30 calendar days from the date of such request or on a mutually agreed to schedule but no longer than 60 days from the date of such request.

a. (a) Data required for the development of load flow cases, short circuit cases, and stability cases, including ten year load forecasts and all critical assumptions that are used in the development of these cases.

b. (b) Any updates to data exchanged in accordance with Section 9.2.1.

b. (c) Short-circuit models for transmission systems that are relevant to the coordination of planning between the two Parties. Fully detailed planning models (up to the next ten (10) years), as requested by either party and on a mutually agreed schedule as a part of the development of any joint planning studies provided for under this Article IX or as otherwise agreed to.

c. (c) The regional plan document produced by the Party and any long-term or short-term reliability assessment documents produced by the Party, the timing of each planned enhancement, and estimated in-service dates and any operating assessment reports produced by the Party.
b. The status of expansion studies, system impact studies and generation interconnection studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies.

c. Identification and status of interconnection and long-term firm transmission service requests that have been received, including associated studies.

d. Transmission system maps in electronic or hard copy format for the Party’s bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two Parties.

(f) Contingency lists for use in load flow and stability analyses, including lists of all single contingency events and multiple facility tower line contingencies, as well as breaker diagrams for the portions of the Party’s transmission system that are relevant to the coordination of planning between the two systems.

g. The timing of each planned enhancement, including estimated completion dates and project mobilization schedules, and indications of the likelihood a system enhancement will be completed and whether the system enhancement should be included in system expansion studies, system impact studies and generation interconnection studies, and all related applications for regulatory approval and the status thereof.

(h) Identification of and status of interconnection requests that have been received and any long-term firm transmission services that have been approved that may impact the operation of a Party’s system in a manner that affects the other Party’s system, shared on the earlier of the identification of the potential impact, within 30 days of such request by the other Party or on a regular schedule as otherwise agreed to by the Parties.

(i) Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between the systems, shared on the earlier of the identification of the potential impact, within 30 days of such request by the other Party, or on a regular schedule as otherwise agreed to by the Parties.

(j) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

(k) Load flow and short-circuit data initially will be exchanged in PSS/E format. To the extent practical, the maintenance and exchange of power system modeling data will be implemented through databases. When feasible, transmission maps and
breaker diagrams will be provided in an electronic format agreed upon by the Parties. Formats for the exchange of other data will be agreed upon by the Parties from time to time.

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Section 9.3 Coordinated System Planning Version: 1.0.0.0 Effective:

1/1/2014 9/17/2010

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

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

9.3.2 Coordinated System Plan.
The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the
Coordinated System Plan as further described in Section 9.3.5. The Coordinated System Plan shall also include the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the Coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses Joint Coordinated System Plan engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses Joint Coordinated System Plan.

9.3.3 Analysis of Interconnection Requests.
In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes Coordinated planning analyses and Network Upgrades will include the following:

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

(b) The coordination of the study results pursuant related to each Party’s business practices manuals, will determine that request for interconnection, the potential impact on Party receiving the request (“direct connect system and on the”) will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the direct connect system will be responsible for communicating coordinated interconnection study results to the direct connect interconnection customer. notify the other Party and convey the information provided in the posting.

(c) (b) — Following the results of either the Feasibility Study or the System Impact Study, the direct connect system will notify the other Party if the
study shows potential reliability concerns on the other Party’s system. 
After reviewing the results, if the potentially impacted Party determines 
that its system may be materially impacted by the interconnection, that 
Party will contact the direct connect system and request participation in 
the applicable interconnection studies. The Parties will coordinate and 
mutually agree on the nature of studies to be performed to test the impacts 
of the interconnection on the potentially impacted Party, who will 
perform the studies. If the Parties cannot mutually agree on the nature of 
the studies to be performed they can resolve the differences through the 
dispute resolution procedures documented in Article XIV. The Parties will 
strive to minimize the costs associated with the coordinated study process.

(de) Any coordinated studies will be performed in accordance with the study 
scope and timeline mutually agreed to in 9.3.3 (cb) above utilizing the 
responsibility options outlined in 9.3.3 (ed) below.

e) If the (d) ——— The potentially impacted Party may participate in the 
coordinated interconnection study identifies study at the System Impact 
Study or Feasibility Study stage by providing input to the studies to be 
performed by the direct connect system. If the constraints found 
require infrastructure additions on the impacted system to mitigate them, 
then the potentially impacted Party may will perform its own analysis, in 
conjunction with Facilities Study as part of the direct connect Party’s 
Interconnection Studies. The Facilities Study. The study cost estimates 
indicated in the study agreement between the direct connect system and 
the interconnection customer whose project requires mitigation of 
constraint(s) found on an will reflect the costs and the associated roles of 
the study participants including the potentially impacted Party’s system 
shall enter into the appropriate Facilities Study agreement as required 
under the impacted Party’s OATT Party. The direct connect system will 
review the cost estimates submitted by all participants for reasonableness, 
based on expected level of participation and responsibilities in the study.

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

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

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

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

(i) In addition, thermal and reactive impacts associated with circulation and other phenomena that result from interconnection and impact the systems of both Parties will be evaluated in the evaluation of specific requests associated with delivery service and in the development of the Coordinated System Plan.

(j) Each Party will maintain a separate interconnection queue. The Parties JRPC will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. The JRPC will post this listing on the Internet site maintained for the communication of information related to the coordinated system planning process. The Internet site will contain links to the web sites of each Party where individual interconnection study results will be maintained.
9.3.4 **Analysis of Long-Term Firm Transmission Service Requests.**

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

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

(b) Upon either the posting to the OASIS of a request for service or the review of studies related to the evaluation of that service request, the Party receiving the request will coordinate the study of the request, pursuant to each Party’s business practices manuals, which will determine whether the potential impact on each Party’s system. The other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the request will be responsible for communicating coordinated study results to the customer requesting such service, notify the other Party and convey the information provided in the posting.

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

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.
If constraints are identified during the coordinated study on the impacted system, then the System Impact Study, the potentially impacted Party may perform its own analysis, participate in conjunction with the coordinated study either by providing input to the studies to be performed by the Party that has received the request for service. The customer whose request for service requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the appropriate facilities study agreement as required under the impacted Party’s OATT. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request’s Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

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

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

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

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

9.3.5 Development of the Coordinated System Plan.

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

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

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties’ systems due to the integration described in the preceding part (a); such system additions or Network Upgrades;

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

9.3.5.2 Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for steps; (a) Coordinated System Plan study described in Section 9.3.5.2.a; and 2) Coordinated System Plan study described in Section 9.3.5.2.b. (a) Every three years, the Parties shall perform a comprehensive, coordinated regional transmission expansion planning study. Sensitivity analyses will be performed, as required, during the off years based on a review by the JRPC and IPSAC of discrete reliability problems or operability issues that arise due to changing system conditions. Ad hoc study groups may be formed as needed to address localized seams issues, or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented, (e.g., a set number of meetings per year and/or develop a protocol for the exchange of studies, report queues, and other relevant information). Projects needed to resolve transmission problems which have been identified by either RTO at any time during the three year planning cycle will be evaluated by the JRPC at least annually for purposes of testing against the Cross-Border cost allocation criteria. Transmission plans to resolve problems will be identified, included in the respective plans of the RTOs, and will be presented to the respective RTO Boards for approval and implementation using each RTOs procedures for approval. Critical upgrades for which the need to begin development is urgent will be presented to the RTO Boards for approval as soon as possible after identification through the

(a) Determining the Need for a Coordinated System Plan Study coordinated planning process. Other projects identified will be presented to the RTO Boards in the normal regional planning process cycle as long as this cycle does not delay the
implementation of a necessary upgrade. Each RTO reserves the right to identify required transmission upgrades to their Board for approval at any time.

(ii) On an annual basis, the Parties shall perform an annual evaluation of transmission issues identified by each Party, including issues from the respective Party’s market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed schedule taking into consideration each Party’s regional planning cycles. The JRPC through each Party’s respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting for consideration by the IPSAC and JRPC.
(ii) Following the annual issues evaluation meeting with IPSAC the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (i) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (ii) if after two consecutive years in which a Coordinated System Plan study has not been performed, and one Party votes in favor of performing a Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study.

(iii) When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study, which shall not exceed 180 calendar days from the date of the JRPC’s determination to perform the study, unless the Parties agree to an alternative start date taking into consideration each Party’s regional planning cycles.

(b) Coordinated System Plan Study Process

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

(ii) The JRPC will develop a scope and procedure for the coordinated inter-regional planning analysis assessment. The scope of the studies will include evaluations of issues resulting from the annual coordinated review and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment.

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

(iv) The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and
each Party's criteria. Stakeholder input will be solicited for potential remedies to identified issues.

(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation evaluations of the transmission system against the reliability criteria, operational performance criteria, and economic performance criteria applicable to each Party. Each Party will provide a baseline model that includes all transmission enhancements included in the party's regional transmission expansion plan, and all of the committed interconnection projects and any associated Network Upgrades.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. The JRPC will develop joint study Exchange of power flow models will be in a format that is acceptable to both Parties and will use a consistent with bus numbering convention and bus naming convention to minimize work that is needed to merge detailed power flow models.

(e) The study will initially evaluate the models and assumptions used for reliability of the regional planning cycle most recently completed. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be accommodated. Known updates combined transmission system. Any Network Upgrades required to resolve criteria violations will be agreed upon and revisions to this included in an updated baseline model will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates.

(f) The performance of the combined transmission systems will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback tested against agreed upon operational and economic criteria, where applicable, using the updated baseline model. Network Upgrades required to the JRPC regarding the study models.

(vii) The IPSAC will have the opportunity to provide input into the development of potential solutions. The JRPC will be responsible for the screening resolve operational and evaluation of potential
solutions, including evaluating the proposed projects for designation as a cross-border allocation project pursuant to Section 9.4.3.1.

(viii) Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements or economic performance criteria violations will be included in the Coordinated System Plan.

(ix) At the completion of the Coordinated System Plan study, the JRPC shall produce a report documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended cross-border allocation projects with the associated cost allocation to the Parties pursuant to Section 9.4.3.1. The JRPC shall provide the Coordinated System Plan study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study report. The final Coordinated System Plan study report shall be posted on each Party’s website.

(x) The JRPC’s recommended cross-border allocation projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties’ Boards for approval and implementation using each Party’s procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform the IPSAC of the outcome of each Party’s review of the recommended cross-border allocation projects.

(g) Economic criteria applicable to either Party will be developed and filed by that Party with input from its stakeholders.

Effective Date: 9/17/2010 - Docket #: ER10-2746-000
9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.

When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT Parties’ Order 2003 compliance filings as accepted by FERC.

9.4.2 Network Upgrades Associated with Transmission Service Requests.

When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT Parties’ Order 2003 compliance filings as accepted by FERC.

9.4.3 Network Upgrades Under Coordinated System Plan.

The Coordinated System Plan will identify cross-border projects as (i) CBBRP; or (ii) CBMEP. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.3.1 Criteria for Project Designation as a Cross-Border Allocation Project:

Projects will be designated in accordance with the following criteria:

9.4.3.1.1 Criteria for Project Designation as a Cross-Border Baseline Reliability Project: Projects that meet all of the following criteria will be designated as CBBRPs: (i) by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria; (ii) the project must be a baseline...
reliability project as defined under the Midwest ISO or PJM Tariffs; (iii) the resulting allocation of Project Cost to the RTO in which the project is not constructed must be a minimum of $10,000,000; (iv) using the Coordinated System Plan power flow model, the contribution of the cross-border RTO to loading on the constrained facility giving rise to the CBBRP must be at least five percent (5%) of the total loading on the constrained facility; and (v) the CBBRP must have an in-service date after December 31, 2007. The Cross-Border Grandfathered Projects document contains a list of projects that will be excluded from designation as a CBBRP notwithstanding the in-service date.

9.4.3.1.2 Criteria for Project Designation as a Cross-Border Market Efficiency Project

Projects that meet all of the following criteria will be designated as a CBMEP if the project: (i) has an estimated Project Cost of $20,000,000 or greater; (ii) is evaluated as part of a Coordinated System Plan or joint study process, as described in section 9.3.5 of the JOA; (iii) meets the threshold benefit to cost ration as prescribed under the terms of, and using the benefit and cost measures prescribed under section 9.4.3.1.2.1 of the JOA; (iv) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project Regionally Beneficial Project under the terms of Attachment FF of the Midwest ISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM RTEP or Midwest ISO OATT shall apply the Project Cost of the CBMEP and not the allocated cost; and (v) addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.

9.4.3.1.2.1 Determination of Benefits to Each RTO from CBMEP

The RTOs shall jointly evaluate the benefits to the combined Midwest ISO and PJM markets, and to each market individually, by evaluating multiple metrics using a multi-year analysis to determine whether a proposed project qualified as a CBMEP. The RTOs shall perform this evaluation as follows:

(a)[e] The RTOs shall utilize a benefit metric to analyze the anticipated annual economic benefits of construction of a proposed CBMEP to Transmission Customers of each RTO. Benefits are measured for a project by the estimated change in the benefit metric with and without the incorporation of the proposed project. The benefit metric is based upon the impact of the project on: (1) APC (adjusted to account for purchases and sales) and (2) NLP. The benefit metric for each RTO
shall be developed by weighting the APC benefit and the NLP benefit. The benefit metric shall be calculated as the sum of seventy percent (70%) times the change in APC benefit for each RTO plus thirty percent (30%) times the change in NLP benefit for each RTO where the change in APC and NLP is calculated by subtracting the APC and NLP values determined without the proposed CBMEP:

\[
\text{Benefit Metric} = (70\% \text{ of change in APC} + 30\% \text{ of change in NLP})
\]

The APC for each RTO represents each RTO’s production costs adjusted for interchange purchases and sales. For each simulation hour in which an RTO is selling interchange, the APC shall be calculated by multiplying the interchange sales MW times the RTO’s generation-weighted LMP and then subtracting this value from the RTO’s production cost. For each simulation hour in which an RTO is purchasing interchange, the APC shall be calculated by multiplying the interchange purchase MW times the RTO’s load-weighted LMP and then adding this value to the RTO’s production cost.

The NLP benefit for each RTO represents each RTO’s gross load payment minus the estimated value of congestion-hedging transmission rights in each RTO. The NLP shall be calculated by multiplying the LMP at each modeled load bus in the RTO by the load (in MW) at the bus, for each simulation hour (load LMP * load (in MW)), and then subtracting from that product the estimated value of congestion-hedging transmission rights for that hour. For each simulation hour, the value of an RTO’s transmission rights shall be calculated by subtracting the RTO generation-weighted LMP from the RTO load-weighted LMP and then multiplying this difference times the lower of the RTO’s total generation MW level or the RTO’s total load MW level.

The benefit metric shall be calculated for each RTO for each year of simulation. Benefits for intermediate years between simulated years will be based on interpolation. The annual benefit for a CBMEP shall be determined as the sum of the benefit values for each RTO. The total project benefit shall be determined by calculating the present value of annual benefits for, at a minimum, the first ten years of project life after the projected in-service year, with a maximum planning horizon of 20 years from the current year.
The RTOs shall employ a threshold benefits-to-costs ratio test to evaluate a potential CBMEP. Only projects that meet the benefits-to-costs ratio threshold shall be designated as a CBMEP. The costs applied in the benefits-to-costs ratio shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the CBMEP are determined from the estimated CBMEP installed costs and the fixed charge rate applicable to the constructing transmission owner(s).

The benefits-to-costs ratio threshold for a project to qualify as a CBMEP shall be 1.25 to 1. To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners’ most recent after-tax embedded cost of capital weighted by each transmission owner’s total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner’s most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

Using the cost allocated to each RTO pursuant to section 9.4.3.2.2 of the JOA, and the Coordinated System Plan model, including using the same simulation years, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project Regionally Beneficial Project under the terms of Attachment FF of the Midwest ISO OATT.

9.4.3.2 Cross-Border Project Shares:

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

9.4.3.2.1 Cost Allocation for Cross-Border Baseline Reliability Projects

a. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and interconnects to the transmission facilities of a Transmission Owner in MISO and the transmission facilities of a Transmission Owner in PJM, the ownership and responsibility to construct shall be based on the RTO boundaries between the connected Transmission Owners in each RTO, unless otherwise agreed to by such Transmission Owners. Each RTO shall recover the costs associated with the portion owned by their...
respective Transmission Owner(s) in accordance with the recovery provisions in the applicable Party’s OATT.

b. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and is located solely within the MISO RTO, the constructing MISO Transmission Owner(s) will work with the PJM Transmission Owner(s) that has/have a reliability-based need that the CBBRP described in this Section 9.4.2.1.b addresses to determine by mutual agreement whether all or a portion of the Network Upgrade Project Cost should be paid for by the PJM Transmission Owner(s). Absent such an agreement with the PJM Transmission Owner(s), the constructing MISO Transmission Owner(s) has/have the following options:
   i. If the CBBRP is not needed to address a reliability issue within the MISO pricing zone(s) where it would be located, the constructing MISO Transmission Owner(s) may elect not to construct the project to address the PJM reliability issue.
   ii. If the CBBRP is needed to address a reliability issue within the MISO pricing zone where it would be located, the constructing MISO Transmission Owner(s) may elect to construct the project as a baseline reliability project as defined in the MISO tariff to address the MISO reliability issue.
   iii. If the CBBRP is needed to address a reliability issue within the MISO pricing zone where it would be located, as an alternative to 9.4.3.2.1.b.ii, the constructing MISO Transmission Owner(s) has/have the option of working with MISO to identify an alternative Network Upgrade to address the reliability issue in the MISO pricing zone.

c. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and is located solely within the PJM RTO, the constructing PJM Transmission Owner(s) will work with the MISO Transmission Owner(s) that has/have a reliability-based need that the CBBRP described in this Section 9.4.3.2.1.c addresses to determine by mutual agreement whether all or a portion of the Network Upgrade Project Cost should be paid for by the MISO Transmission Owner(s). Absent such an agreement with the MISO Transmission Owner(s), the constructing PJM Transmission Owner(s) has/have the following options:
   i. If the CBBRP is not needed to address a reliability issue within PJM, the constructing PJM Transmission Owner(s) may elect not to construct the project to address the MISO reliability issue.
   ii. If the CBBRP is needed to address a reliability issue within PJM, the constructing PJM Transmission Owner(s) may elect to construct the project as a baseline reliability project as defined in the PJM tariff to address the PJM reliability issue.
   iii. If the CBBRP is needed to address a reliability issue within PJM, as an alternative to 9.4.3.2.1.c.ii, the constructing PJM Transmission Owner(s) has/have the option of working with PJM
9.4.3.2.2

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

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

a. Cost Allocation for Cross-Border Market Efficiency Projects

For CBMEP’s that meet all of the qualifications in section 9.4.3.1.2, 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 9.4.3.1.2.1.a.

9.4.3.3 Determination of Cross-Border Cost Allocation Share Outside of Coordinated System Plan:

Either RTO may request that a project be tested against the cross-border cost allocation criteria during the interim periods between periodic formal releases of the Coordinated System Plan. The RTOs will conduct reviews between the formal cycles on at least an annual basis. Such tests will be performed on the best available joint planning model, as determined by the JRPC.

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

9.4.3.4 Cost Recovery of Cross-Border Allocation Shares:

The cost recovery of any share of cost of a border project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.
9.4.3.5 Transmission Owners Filing Rights:

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

9.4.3.6 Amendments:

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

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TAB B

Clean Version of Revised JOA Provisions
Section 9.1 Administration; Committees Version: 1.0.0 Effective: 1/1/2014

9.1 Administration; Committees.

9.1.1 Joint RTO Planning Committee.

The ISC shall form, as a subcommittee, a Joint RTO Planning Committee (JRPC), comprised of representatives of the Parties’ respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, every other year, to designate a Chairman of the JRPC to serve a one-year calendar term. The ISC shall designate the first Chairman. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings. The JRPC shall coordinate the coordinated system planning under this Agreement.

For the purpose of coordinated system planning, the JRPC shall meet no less than twice per year. The JRPC may meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

9.1.1.1 JRPC Responsibilities

The JRPC is the decision making body for coordinated system planning. The Interregional Planning Stakeholder Advisory Committee (IPSAC) and other stakeholder groups may provide input to the JRPC.

Responsibilities of the JRPC include the following:

(a) On an annual basis the JRPC shall conduct a review of identified transmission issues in accordance with section 9.3.5.2.a of this Agreement.

(b) The JRPC, with input from the IPSAC, shall determine if a Coordinated System Plan study should be performed. If yes, such study shall be performed in accordance with section 9.3.5.2.b.

(c) Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed to by the Parties, the JRPC shall develop common power system analysis models to perform coordinated system planning, as well as models for power flow analyses, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the Parties, the JRPC will direct the performance of a detailed review of the appropriateness of applicable power system models.

(d) Coordinate all planning activities under this Article IX, including the exchange of data.

(e) Support the review by any federal or provincial agency of elements of the Coordinated System Plan.
(f) Support the review by multi-state entities to facilitate the addition of inter-
state transmission facilities.

(g) Establish working groups as necessary to provide adequate review and
development of the regional plans.

(h) Establish a schedule for the rotation of responsibility for data
management, coordination of stakeholder meetings, coordination of
analysis activities, report preparation, and other activities.

9.1.1.2 Participating in Multi-Party Studies
The JRPC may combine with or participate in similarly established joint planning
committees amongst multiple entities engaging in coordinated planning studies under
tariff provisions or established under other joint agreements to which a Party is a
signatory, for the purpose of providing for broader inter-regional planning coordination.

9.1.1.3 Coordinated System Planning Website
Each Party shall host its own website for communication of information related to
interregional transmission coordination procedures. Under its direction, the JRPC shall
 coordinate with the Parties to ensure that all information and documents posted on each
Party’s respective website is accurate and consistent. Each Party’s website shall contain,
at a minimum, the following information:
   (a) Link to this Joint Operating Agreement
   (b) Notice of scheduled IPSAC meetings
   (c) Links to materials for IPSAC meetings
   (d) Documents relating to Coordinated System Plan studies

9.1.2 Interregional Planning Stakeholder Advisory Committee
The Parties shall form an IPSAC, in which participation is open to all stakeholders. The
IPSAC shall facilitate stakeholder review and input into coordinated system planning
with respect to the development of the Coordinated System Plan. IPSAC meetings shall
be facilitated by the JRPC.

For the purpose of coordinated system planning, the IPSAC shall meet no less than once
per year. The IPSAC may meet more frequently during the development of a
Coordinated System Plan study as determined to be necessary by the Parties.
The JRPC shall meet annually with the IPSAC to review identified transmission issues
and provide input on whether a Coordinated System Plan study should be performed.
IPSAC meetings shall be on a mutually agreed to date determined by the JRPC.

The IPSAC will provide input to the JRPC on whether a Coordinated System Plan study
should be performed pursuant to Section 9.3.5.2.a. If it is determined by the JRPC that a
study should be performed, the IPSAC will provide input to the JRPC during the
performance of the Coordinated System Plan study pursuant to Section 9.3.5.2.b.
9.2 Data and Information Exchange.

9.2.1 Annual Data and Information Exchange Requirement

In support of interregional planning coordination, each Party shall provide the other with the following data and information on an annual basis and will follow the stipulations for such exchange as noted below.

(a) Power flow models for projected system conditions for the planning horizon (up to the next ten (10) years) that include planned generation development and retirements, planned transmission facilities and seasonal load projections.

(b) System stability models with detailed dynamic modeling of generators and other active elements.

(c) Production cost models for projected system conditions for the planning horizon that include generation and load forecasts and planned transmission facilities.

(d) Assumptions used in development of above power flow, stability and production cost models.

(e) Contingency lists for use in power flow, stability, and production cost analyses.

Models provided will be consistent with those used in the respective Party’s planning processes. Formats for the exchange of data will be agreed upon by the Parties from time to time. Parties can provide the best available information and will not be required to develop unique models to meet the requirements of this Agreement. Data compiled through other multi-regional modeling efforts can be used to meet the data exchange requirements of this Agreement as agreed to in writing by both Parties. This annual data exchange will be completed during the first quarter of the calendar year, unless Parties agree in writing to a different timeline.

9.2.2 Data and Information Exchange upon Request

In addition to the data and information specified in Section 9.2.1, each Party shall provide the other with the following data and information upon request. Unless otherwise indicated, such data and information shall be provided as requested by either Party, as available, within 30 calendar days from the date of such request or on a mutually agreed to schedule.

a. Any updates to data exchanged in accordance with Section 9.2.1.

b. Short-circuit models for transmission systems that are relevant to the coordination of planning between the two Parties.

c. The regional plan document produced by the Party and any long-term or short-term reliability assessment documents produced by the Party, the timing of each planned enhancement, and estimated in-service dates.

d. The status of expansion studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies.
Identification and status of interconnection and long-term firm transmission service requests that have been received, including associated studies.

Transmission system maps in electronic or hard copy format for the Party’s bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two Parties.

Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

Section 9.3 Coordinated System Planning Version: 1.0.0 Effective: 1/1/2014

9.3  Coordinated System Planning.

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

9.3.1  Single Party Planning.

Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of the Party, NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents its annual regional plan prepared according to the procedures, methodologies, and business rules documented by the region. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party’s OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties’ respective systems.
9.3.2 **Coordinated System Plan.**
The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.5. The Coordinated System Plan shall also include the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses.

9.3.3 **Analysis of Interconnection Requests.**
In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

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

(b) The coordination of the study results, pursuant to each Party’s business practices manuals, will determine the potential impact on the direct connect system and on the impacted Party. The direct connect system will be responsible for communicating coordinated interconnection study results to the direct connect interconnection customer.

(c) After reviewing the results, if the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate and mutually agree on the nature of studies to be performed to test the impacts
of the interconnection on the potentially impacted Party. If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV. The Parties will strive to minimize the costs associated with the coordinated study process.

(d) Any coordinated studies will be performed in accordance with the study scope and timeline mutually agreed to in 9.3.3 (c) above utilizing the responsibility options outlined in 9.3.3 (e) below.

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

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

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

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

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

(j) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. These lists will be presented annually to the IPSAC.
9.3.4 Analysis of Long-Term Firm Transmission Service Requests.
In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

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

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

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

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

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

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

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

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

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

9.3.5 Development of the Coordinated System Plan.

9.3.5.1 Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties’ systems. Each Party’s annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Section, to obtain financial compensation due to the impact of another Party’s plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:
(a) Integrate the Parties’ respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation, market participant funded, or merchant transmission projects) and Network Upgrades identified jointly by the Parties, together with alternatives to Network Upgrades that were considered;

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

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

9.3.5.2 Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for a Coordinated System Plan study described in Section 9.3.5.2.a; and 2) Coordinated System Plan study described in Section 9.3.5.2.b.

(a) Determining the Need for a Coordinated System Plan Study
   (i) On an annual basis, the Parties shall perform an annual evaluation of transmission issues identified by each Party, including issues from the respective Party’s market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed to schedule taking into consideration each Party’s regional planning cycles. The JRPC through each Party’s respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting, for consideration by the IPSAC and JRPC.
(ii) Following the annual issues evaluation meeting with IPSAC the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (i) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (ii) if after two consecutive years in which a Coordinated System Plan study has not been performed, and one Party votes in favor of performing a Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study.

(iii) When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study, which shall not exceed 180 calendar days from the date of the JRPC’s determination to perform the study, unless the Parties agree to an alternative start date taking into consideration each Party’s regional planning cycles.

(b) Coordinated System Plan Study Process

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

(ii) The JRPC will develop a scope and procedure for the coordinated planning analysis. The scope of the studies will include evaluations of issues resulting from the annual coordinated review and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment.

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

(iv) The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party’s criteria. Stakeholder input will be solicited for potential remedies to identified issues.
(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation of the transmission system against the reliability criteria, operational performance criteria, and economic performance criteria applicable to each Party.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. The JRPC will develop joint study models consistent with the models and assumptions used for the regional planning cycle most recently completed. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be accommodated. Known updates and revisions to this model will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback to the JRPC regarding the study models.

(vii) The IPSAC will have the opportunity to provide input into the development of potential solutions. The JRPC will be responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as a cross-border allocation project pursuant to Section 9.4.3.1.

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

(ix) At the completion of the Coordinated System Plan study, the JRPC shall produce a report documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended cross-border allocation projects with the associated cost allocation to the Parties pursuant to Section 9.4.3.1. The JRPC shall provide the Coordinated System Plan study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study report. The final Coordinated System Plan study report shall be posted on each Party’s website.
The JRPC’s recommended cross-border allocation projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties’ Boards for approval and implementation using each Party’s procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform the IPSAC of the outcome of each Party’s review of the recommended cross-border allocation projects.

Section 9.4 Allocation of Costs of Network Upgrades Version: 1.0.0 Effective:

1/1/2014

9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.

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

9.4.2 Network Upgrades Associated with Transmission Service Requests.

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

9.4.3 Network Upgrades Under Coordinated System Plan.

The Coordinated System Plan will identify cross-border projects as (i) CBBRP; or (ii) CBMEP. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs.
Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.3.1 Criteria for Project Designation as a Cross-Border Allocation Project:

Projects will be designated in accordance with the following criteria:

9.4.3.1.1 Criteria for Project Designation as a Cross-Border Baseline Reliability Project: Projects that meet all of the following criteria will be designated as CBBRPs: (i) by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria; (ii) the project must be a baseline reliability project as defined under the Midwest ISO or PJM Tariffs.

9.4.3.1.2 Criteria for Project Designation as a Cross-Border Market Efficiency Project

Projects that meet all of the following criteria will be designated as a CBMEP if the project: (i) has an estimated Project Cost of $20,000,000 or greater; (ii) is evaluated as part of a Coordinated System Plan or joint study process, as described in section 9.3.5 of the JOA; (iii) meets the threshold benefit to cost ratio as prescribed under the terms of, and using the benefit and cost measures prescribed under section 9.4.3.1.2.1 of the JOA; (iv) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the Midwest ISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM RTEP or Midwest ISO OATT shall apply the Project Cost of the CBMEP and not the allocated cost; and (v) addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.

9.4.3.1.2.1 Determination of Benefits to Each RTO from CBMEP

The RTOs shall jointly evaluate the benefits to the combined Midwest ISO and PJM markets, and to each market individually, by evaluating multiple metrics using a multi-year analysis to determine whether a proposes project qualified as a CBMEP. The RTOs shall perform this evaluation as follows:

(a) The RTOs shall utilize a benefit metric to analyze the anticipated annual economic benefits of construction of a proposed CBMEP to Transmission Customers of each RTO. Benefits are measured for a project by the estimated change in the benefit metric with and without the incorporation of the proposed project. The benefit metric is based upon the impact of the project on: (1) APC (adjusted to account for purchases and sales) and (2) NLP. The benefit metric for each RTO shall be developed by weighting the APC benefit and the NLP benefit. The benefit metric shall be calculated as the sum of seventy percent (70%) times the change in APC benefit for each RTO plus thirty
percent (30%) times the change in NLP benefit for each RTO where
the change in APC and NLP is calculated by subtracting the APC and
NLP values determined without the proposed CBMEP:

\[
\text{Benefit Metric} = (70\% \text{ of change in APC} + 30\% \text{ of change in NLP})
\]

The APC for each RTO represents each RTO’s production costs
adjusted for interchange purchases and sales. For each simulation
hour in which an RTO is selling interchange, the APC shall be
calculated by multiplying the interchange sales MW times the RTO’s
generation-weighted LMP and then subtracting this value from the
RTO’s production cost. For each simulation hour in which an RTO is
purchasing interchange, the APC shall be calculated by multiplying the
interchange purchase MW times the RTO’s load-weighted LMP and
then adding this value to the RTO’s production cost.

The NLP benefit for each RTO represents each RTO’s gross load
payment minus the estimated value of congestion-hedging
transmission rights in each RTO. The NLP shall be calculated by
multiplying the LMP at each modeled load bus in the RTO by the load
(in MW) at the bus, for each simulation hour (load LMP * load (in
MW)), and then subtracting from that product the estimated value of
congestion-hedging transmission rights for that hour. For each
simulation hour, the value of an RTO’s transmission rights shall be
calculated by subtracting the RTO generation-weighted LMP from the
RTO load-weighted LMP and then multiplying this difference times
the lower of the RTO’s total generation MW level or the RTO’s total
load MW level.

The benefit metric shall be calculated for each RTO for each year of
simulation. Benefits for intermediate years between simulated years
will be based on interpolation. The annual benefit for a CBMEP shall
be determined as the sum of the benefit values for each RTO. The
total project benefit shall be determined by calculating the present
value of annual benefits for, at a minimum, the first ten years of
project life after the projected in-service year, with a maximum
planning horizon of 20 years from the current year.

(b) The RTOs shall employ a threshold benefits-to-costs ratio test to
evaluate a potential CBMEP. Only projects that meet the benefits-to-
costs ratio threshold shall be designated as a CBMEP. The costs
applied in the benefits-to-costs ratio shall be the present value, over the
same period for which the project benefits are determined, of the
annual revenue requirements for the project. The annual revenue
requirements for the CBMEP are determined from the estimated
CBMEP installed costs and the fixed charge rate applicable to the constructing transmission owner(s).

The benefits-to-costs ratio threshold for a project to qualify as a CBMEP shall be 1.25 to 1. To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners’ most recent after-tax embedded cost of capital weighted by each transmission owner’s total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner’s most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

(c) Using the cost allocated to each RTO pursuant to section 9.4.3.2.2 of the JOA, and the Coordinated System Plan model, including using the same simulation years, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the Midwest ISO OATT.

9.4.3.2 Cross-Border Project Shares:

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

9.4.3.2.1 Cost Allocation for Cross-Border Baseline Reliability Projects

a. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and interconnects to the transmission facilities of a Transmission Owner in MISO and the transmission facilities of a Transmission Owner in PJM, the ownership and responsibility to construct shall be based on the RTO boundaries between the connected Transmission Owners in each RTO, unless otherwise agreed to by such Transmission Owners. Each RTO shall recover the costs associated with the portion owned by their respective Transmission Owner(s) in accordance with the recovery provisions in the applicable Party’s OATT.

b. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and is located solely within the MISO RTO, the constructing MISO Transmission Owner(s) will work with the PJM Transmission Owner(s) that has/have a reliability-based need that the CBBRP described in this Section 9.4.2.1.b addresses to determine by mutual agreement whether all or a portion of the Network Upgrade Project Cost should be paid for by the PJM Transmission Owner(s). Absent such an agreement with the PJM Transmission Owner(s), the constructing MISO
Transmission Owner(s) has/have the following options:

i. If the CBBRP is not needed to address a reliability issue within the MISO pricing zone(s) where it would be located, the constructing MISO Transmission Owner(s) may elect not to construct the project to address the PJM reliability issue.

ii. If the CBBRP is needed to address a reliability issue within the MISO pricing zone where it would be located, the constructing MISO Transmission Owner(s) may elect to construct the project as a baseline reliability project as defined in the MISO tariff to address the MISO reliability issue.

iii. If the CBBRP is needed to address a reliability issue within the MISO pricing zone where it would be located, as an alternative to 9.4.3.2.1.b.ii, the constructing MISO Transmission Owner(s) has/have the option of working with MISO to identify an alternative Network Upgrade to address the reliability issue in the MISO pricing zone.

c. For a CBBRP that meets the criteria in Section 9.4.3.1.1 and is located solely within the PJM RTO, the constructing PJM Transmission Owner(s) will work with the MISO Transmission Owner(s) that has/have a reliability-based need that the CBBRP described in this Section 9.4.3.2.1.c addresses to determine by mutual agreement whether all or a portion of the Network Upgrade Project Cost should be paid for by the MISO Transmission Owner(s). Absent such an agreement with the MISO Transmission Owner(s), the constructing PJM Transmission Owner(s) has/have the following options:

i. If the CBBRP is not needed to address a reliability issue within PJM, the constructing PJM Transmission Owner(s) may elect not to construct the project to address the MISO reliability issue.

ii. If the CBBRP is needed to address a reliability issue within PJM, the constructing PJM Transmission Owner(s) may elect to construct the project as a baseline reliability project as defined in the PJM tariff to address the PJM reliability issue.

iii. If the CBBRP is needed to address a reliability issue within PJM, as an alternative to 9.4.3.2.1.c.ii, the constructing PJM Transmission Owner(s) has/have the option of working with PJM to identify an alternative Network Upgrade to address the reliability issue in PJM.

9.4.3.2.2 Cost Allocation for Cross-Border Market Efficiency Projects

For CBMEP’s that meet all of the qualifications in section 9.4.3.1.2, 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 9.4.3.1.2.1.a.
9.4.3.3 Determination of Cross-Border Cost Allocation Share Outside of Coordinated System Plan:

Either RTO may request that a project be tested against the cross-border cost allocation criteria during the interim periods between periodic formal releases of the Coordinated System Plan. The RTOs will conduct reviews between the formal cycles on at least an annual basis. Such tests will be performed on the best available joint planning model, as determined by the JRPC. The joint planning model will be a minimum 5-year horizon case, modeling peak summer conditions, and will be developed by February of each year. It will be based on the current RTEP basecase for PJM and the current MTEP basecase for the Midwest ISO. The basecase developed by each RTO will be based on documented procedures, which, in turn, will guide the development of the joint RTO planning model. Any disputes that arise will be resolved through the dispute resolution procedures documented in Article XIV. Each year the model will be updated by the RTOs to include changes to long term firm transmission service, load forecast, topology changes, generation additions/retirements and any other relevant system changes that may have occurred since the previous years’ basecase development. The joint RTO planning model will be available to any member of PJM or the Midwest ISO.

9.4.3.4 Cost Recovery of Cross-Border Allocation Shares:

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

9.4.3.5 Transmission Owners Filing Rights:

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

9.4.3.6 Amendments:

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

Table of MISO’s Order No. 1000 Interregional Stakeholder Meetings
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<td>Regional Expansion and Benefits Criteria Task Force (“RECB TF”)</td>
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<td>11/29/2012 (joint meeting with PAC)</td>
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## MISO Stakeholder Forums

### Dates of Meetings and Conference Calls

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TAB D

Testimony of Jennifer Curran
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. ) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF JENNIFER CURRAN
ON BEHALF OF

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

AND MISO TRANSMISSION OWNERS

July 10, 2013
I. INTRODUCTION

A. Witness Background

Q: Please state your name, current position and business address.

A: My name is Jennifer Curran. I am employed by the Midcontinent Independent System Operator, Inc. (“MISO”) (formerly, Midwest Independent Transmission System Operator, Inc.), and my business address is at 720 City Center Drive, Carmel, Indiana 46032.

Q: Please briefly describe your educational background and professional experience.

A: I hold a Bachelor of Science degree in Mechanical Engineering from Rice University, and a Master of Business Administration from Duke University. Prior to joining MISO in July 2004, I was Manager of Power Generation and Supply Strategy for the Mid-Atlantic and Mid-Continent Regions at what was then known as Reliant Resources.

Q: Please describe your current position and responsibilities, and your background with MISO.

A: I was recently appointed Vice-President for Transmission of MISO. My previous title was Executive Director of Transmission Infrastructure Strategy, a position I held since October 2009. From February 2007 to October 2009, I was Director of Transmission Infrastructure Strategy.

As Vice-President for Transmission of MISO, I retained my previous functions, and my additional responsibilities include oversight of the generator interconnection and transmission service queue tariff processes. I am currently responsible for directing the development and execution of strategies to enable necessary transmission infrastructure investment through the MISO transmission planning process. In this role, I focus on
supporting the state and federal regulatory and business case requirements for transmission infrastructure. In addition, I am responsible for leading the development of effective transmission cost allocation methodologies. I also serve as the MISO staff liaison to the Board of Directors System Planning Committee, which is responsible for providing overall direction to the MISO planning staff and reviewing the MISO Transmission Expansion Plan.

I previously served as the MISO staff liaison to the stakeholder committee charged with improvement of MISO’s cost allocation method, the Regional Expansion Criteria and Benefits Task Force (“RECB TF”). Also, I previously served as the MISO staff liaison to the Planning Advisory Committee (“PAC”), which is the stakeholder committee that provides advice to the MISO planning staff on policy matters related to the process, integrity, and fairness of the MISO-wide transmission expansion plan and cost allocation. I have also served as the Director of Performance Assurance at MISO, responsible for business and financial planning for the operations areas of the company.

Q: Have you sponsored any other testimony before regulatory commissions?

A: Yes. I have submitted prepared testimony before the Federal Energy Regulatory Commission (“FERC” or “Commission”) involving matters specific to MISO. In particular, I have submitted testimony in support of the revisions to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”) that MISO and certain of its Transmission Owners filed in Docket No. ER10-1791-000, where the Commission approved MISO’s Tariff provisions on the establishment of Multi-Value Projects (“MVPs”) and the regional (i.e., system-wide) allocation of MVP costs. In addition, I have submitted testimony in Docket Nos. ER12-715-000 and ER12-715-003,
relating to Schedule 39 of the Tariff, as well as in Docket Nos. ER13-187-000, relating to regional compliance with Order No. 1000, and ER13-186-000, relating to MISO’s modification of the cost allocation methodology for Baseline Reliability Projects (“BRPs”). I have also submitted testimony in support of MISO in other proceedings before the Commission and state regulatory commissions.

B. Purpose of Testimony

Q: What is the purpose of your testimony?

A: My testimony will discuss and support MISO’s and the MISO Transmission Owners’ (“MISO TOs”) proposed compliance with the interregional cost allocation requirements of Order No. 1000, as affirmed on rehearing by Order Nos. 1000-A and 1000-B, through revisions to MISO’s Joint Operating Agreement (“JOA”) with PJM Interconnection, L.L.C. (“PJM”).

II. MISO-PJM JOA’S BACKGROUND

Q: Please describe briefly the background of the JOA between MISO and PJM.

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The supporting MISO TOs for purposes of this testimony consist of: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Gulf States Louisiana, L.L.C.; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Great River Energy; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Otter Tail Power Company; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; and Wabash Valley Power Association, Inc.
A: MISO and PJM first filed the JOA on December 31, 2003 pursuant to the Commission’s earlier directives. The Commission conditionally accepted the JOA on March 18, 2004. Since then, the JOA has been amended several times. For example, the Commission further directed MISO and PJM to amend the JOA to provide for interregional coordination of regional planning and sharing of Transmission Owner plans. The RTOs submitted the requested changes in an April 2, 2004 filing, which the Commission accepted on August 5, 2004.

Q: Please describe briefly the history of the JOA’s provisions regarding cross-border projects.

A: On November 18, 2004, the Commission directed the RTOs to develop a proposal for interregional cost allocation of facilities constructed in one RTO but that provide benefits to customers in the other RTO. MISO and PJM complied with this directive in a filing made on May 17, 2005, which proposed a cost allocation method for certain cross-border reliability projects called Cross-Border Baseline Reliability Projects (“CBBRPs”). The Commission conditionally accepted this proposal on November 21, 2005. The costs of CBBRPs were to be allocated using a load flow model that identifies project beneficiaries based on cost causation principles. Although the Commission determined that the proposal would identify the beneficiaries and allocate the cross-border project costs more accurately than the then existing license plate rate structure, the Commission also required the RTOs

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to provide greater detail regarding the joint planning model to be used for cross-border cost allocation.

In response, MISO and PJM proposed to use a transfer distribution factor (“DFAX”) analysis to calculate the size of each RTO’s flows affecting the constraint requiring relief from a cross-border reliability project. However, MISO and PJM could not agree on one element of the DFAX analysis, namely how counterflows should be netted against positive flows. The Commission selected MISO’s method for counterflow netting of CBBRPs on January 31, 2008.

The Commission also directed MISO and PJM to propose a cross-border cost allocation methodology for economic projects. The RTOs filed such a proposal on January 28, 2009 for projects called Cross-Border Market Efficiency Projects (“CBMEPs”). The parties proposed to allocate CBMEP costs to each RTO in proportion to the present value of its share of the annual benefits calculated for the project. The Commission accepted this proposal as just and reasonable on November 3, 2009.4

Q: Have any cross-border projects been approved under the JOA to date?
A: To date, no cross-border projects have been approved for cost allocation under the existing JOA provisions.

III. Background on MISO’s Order No. 1000 Approved Regional Cost Allocation Methods

Q: What project types in MISO have regional cost allocation?

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Under MISO’s Tariff, the project types with regional cost allocation currently include Market Efficiency Projects ("MEPs") and MVPs. The Commission previously approved MISO’s cost allocation methodologies for MEPs and MVPs. In addition, in its March 22, 2013 order conditionally approving MISO’s Order No. 1000 regional compliance filing, the Commission approved MISO’s proposal to use the MEP and MVP project categories as MISO’s means of complying with the regional planning and cost allocation requirements of Order No. 1000.1

Q: Please explain the MEP category of transmission projects.

A: MEPs are primarily economic upgrades that meet specific criteria, including that the project costs $5 million or more, primarily involves facilities with a voltage of 345 kV or greater, and meets a benefit-to-cost requirement of 1.25 or greater. MEPs are evaluated against multiple future scenarios to capture a range of potential future outcomes based on a number of key drivers, such as: demand and energy growth rates, demand response and energy efficiency programs, fuel prices, public policy requirements, generation retirements, etc.

Although MEPs are primarily economic upgrades, they can also address reliability issues. For example, under the MISO Tariff, if a project meets both the BRP2 and MEP criteria, then the project is approved as an MEP. Also, as part of the MEP evaluation, a reliability “no harm” test is performed and if reliability upgrades are identified the costs of those

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2 Under Section II.A.1 of Attachment FF to the Tariff BRPs are defined as Network Upgrades designed to ensure that the MISO Transmission System remains in compliance with applicable national Electric Reliability Organization ("ERO") reliability standards, and reliability standards adopted by Regional Reliability Organizations that are applicable within MISO.
upgrades would be included in the MEP. For projects that meet the MEP criteria, 80% of the costs are allocated to all Transmission Customers in the appropriate Local Resource Zones based on the distribution of benefits across the Local Resource Zones, and 20% of the costs are allocated on a system-wide basis to all Transmission Customers.\(^5\)

**Q:** Please explain the MVP category of transmission projects.

**A:** MVPs are defined as one or more Network Upgrades that address a common set of Transmission Issues and satisfy the conditions listed in Sections II.C.1, II.C.2, and II.C.3 of Attachment FF of the Tariff.\(^6\) MVPs are evaluated on a portfolio basis, with benefits that are spread broadly across the MISO footprint, based on one of three benefit criteria: (1) to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation; (2) to provide multiple types of economic value across multiple pricing zones; or (3) to address, through the development of a robust Transmission System, multiple Transmission Issues associated with reliability and economic issues affecting multiple pricing zones.\(^7\) The costs of approved MVPs are allocated 100 percent on a system-wide basis.\(^8\) The MVP transmission project category, with its associated broad-based cost allocation, is designed to, among other things, enable MISO to address multiple reliability

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\(^5\) The cost allocation across the Local Resource Zones is determined using the distribution of adjusted production cost savings. Adjusted production cost is defined as the total production cost of the generation fleet adjusted for import costs and export revenues. Tariff, Attachment FF, Sections II.B.1.a and III.A.2.f.ii.

\(^6\) Attachment FF, section II.C.

\(^7\) Attachment FF, sections II.C.1, II.C.2 and II.C.3

\(^8\) Section III.A.2.g of Attachment FF.
needs and provide economic value through regional transmission development, while addressing identified transmission needs driven by public policy requirements.

Q: What type of regionally cost-allocated project is MISO proposing to use to evaluate and approve interregional projects with PJM, which will be subject to interregional cost allocation?

A: MISO is proposing to evaluate and approve as MEPs all interregional projects subject to interregional cost allocation with PJM. This is consistent with the requirement of Order No. 1000 that, to be eligible for interregional cost allocation, an interregional project must also be approved and included in the neighboring transmission regions’ respective regional plans for purposes of cost allocation.

Q: Why is MISO not proposing to use the regional project type of MVPs to approve interregional projects with interregional cost allocation with PJM?

A: MVPs are required to be evaluated on a portfolio basis to ensure that the benefits are spread broadly across the MISO region in line with the 100 percent system-wide allocation of costs for MVPs. To be approved under MISO’s regional cost allocation methods as an MVP, an interregional project would have to meet this same requirement tied to 100 percent regional cost allocation, which does not align with the current regional cost allocation methods of the PJM planning region. Taking into account these requirements for regional approval of MVPs, which differ from the cost allocation processes and methods of the PJM planning region, MISO believes the MEP methodology better aligns with the processes of PJM at this time, and provides a more likely path towards the approval of interregional projects to the benefit of customers in both regions given the current difference in MISO’s and PJM’s regional cost allocation mechanisms. For
example, MEPs would make it more feasible for MISO and PJM to resolve any differences between their modeling and other data that could otherwise hamper the effective joint evaluation of transmission needs and the benefits of potential interregional projects.

IV. **Background on Baseline Reliability Projects**

Q: **Please explain the BRP category of MISO transmission projects.**

A: BRPs are Network Upgrades designed to ensure that the MISO Transmission System remains in compliance with applicable national Electric Reliability Organization ("ERO") reliability standards and reliability standards adopted by Regional Reliability Organizations that are applicable within MISO. The costs of BRPs are recovered from the Transmission Customers of the pricing zone where the BRP is located.

Q: **Has MISO changed the cost allocation treatment of BRPs since the CBBRP methodology was instituted in 2007?**

A: Yes. In Docket No. ER13-186, the Commission accepted MISO’s proposal to remove regional cost allocation for BRPs and assign all BRP costs to the pricing zone where the BRP is located, effective June 1, 2013. The Commission found that MISO’s proposal assigns BRP costs in a manner roughly commensurate with the predominantly local nature of the benefits BRPs provide.

V. **Interregional Cost Allocation**

A. **Applicable Project Types**

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10. Section III.A.2.c of Attachment FF of MISO’s Tariff.
Q: What types of MISO transmission projects will be covered by interregional cost allocation between MISO and PJM?

A: MISO proposes to include the CBMEP project type within the scope of its Order No. 1000 interregional cost allocation method with PJM. MISO has determined that CBMEPs, as they currently exist, are fully compliant with the Commission’s six interregional cost allocation principles. In addition, CBMEPs, which must also qualify as MEPs pursuant to Attachment FF of MISO’s Tariff, are eligible for regional cost allocation within MISO pursuant to the MISO Transmission Expansion Plan (“MTEP”). In contrast, because BRPs are no longer included in MISO’s MTEP for purposes of regional cost allocation, BRPs in MISO are not eligible for interregional cost allocation as defined in Order No. 1000 as CBBRPs. Reliability-based projects may still be considered as part of the coordinated planning process with PJM for purposes of efficiently maintaining reliability in MISO and PJM.

Q: Please explain the CBMEP category of transmission projects.

A: CBMEPs are primarily economic upgrades that meet specific criteria, including: (1) a project cost of $20 million or greater; (2) evaluation as part of the Coordinated System Plan; (3) a defined benefit-to-cost requirement of 1.25; and (4) meets the applicable criteria under the MISO and PJM tariff for regional approval.¹¹ A CBMEP can be located solely within MISO or PJM and is not limited to the tie-line situation addressed by Order No. 1000 with regard to the Commission’s requirements for an interregional cost allocation methodology. For projects that meet the CBMEP criteria, the costs are allocated to MISO.

¹¹ JOA, section 9.4.3.1.2.
and PJM in proportion to the benefits calculated for each RTO.\textsuperscript{12} The calculated benefits represent a weighting of 70 percent adjusted production cost savings and 30 percent reduction in net load payments.\textsuperscript{13}

Q: **How does MISO’s proposal to use MEPs for regional approval allow for consideration of transmission needs driven by reliability?**

A: Under MISO’s Tariff, if a proposed project meets the criteria for both MEPs and BRPs, the project will be classified as an MEP. The Tariff therefore recognizes that MEPs can also address reliability issues and, therefore, an interregional project also can address reliability issues. Further, any upgrades that are required to address reliability issues in connection with a MISO-PJM interregional project will be included in the overall costs of the project to ensure the project is able to provide the expected economic benefits to both regions.

Q: **How does MISO’s proposal to use the MEP project category for regional evaluation and approval of interregional projects allow for consideration of transmission needs driven by public policy requirements.**

A: Although MISO’s proposal does not include a specific benefit metric or project type for transmission needs driven by public policy requirements, the joint evaluation of proposed CBMEPs will use jointly developed future scenarios that will include the transmission needs driven by public policy requirements that have been identified through MISO’s and PJM’s respective regional planning processes.\textsuperscript{14} Inclusion of each region’s public policy-driven transmission needs in the jointly developed future scenarios used to identify

\textsuperscript{12} *Id.* at section 9.4.3.2.2.

\textsuperscript{13} *Id.* at section 9.4.3.1.2.1.

\textsuperscript{14} *Id.* at section 9.3.5.2(b)(vi).
and evaluate CBMEPs will capture the potential economic benefits provided by the resources included in the RTOs’ respective regional planning processes to address transmission needs driven by these public policy requirements. In addition, when MISO considers the CBMEP for approval as an MEP, the evaluation will include multiple future scenarios that would include the public policy requirement-driven transmission needs identified through the MISO regional planning process, established in Attachment FF of MISO’s Tariff.

Q: Do the PJM Transmission Owners ("PJM TOs") agree with retaining the existing CBMEP provisions for compliance with the Order No. 1000 interregional cost allocation requirements?

A: My understanding is that during discussions between MISO and the PJM TOs preceding the present filing, the PJM TOs indicated they agree that the existing CBMEP provisions should be retained. However, as further discussed below, the PJM TOs did not agree with MISO that CBMEPs should be the only project type for interregional cost allocation.

VI. MISO’s Proposed Revisions to CBBRP Cost Allocation

Q: Please explain MISO’s proposed revisions to the JOA’s provisions regarding CBBRPs.

A: As previously mentioned, I believe that MISO and the PJM TOs agree that CBMEPs should be retained in their current form for the purposes of assessing interregional cost allocation. With regard to CBBRPs, MISO is proposing to remove the existing flow-based cost allocation mechanisms for CBBRPs and instead to include provisions that would allow for tie-lines that interconnect to the transmission facilities of Transmission Owners in MISO and in PJM to be designated as CBBRPs, with ownership and responsibility to
build the relevant facilities to be shared based on the RTO boundaries between the
connected Transmission Owners in the respective RTOs, or in another mutually agreed
manner between the Transmission Owners in each RTO to which the CBBRP is
interconnecting. In addition, one or more Transmission Owners from MISO and PJM may
share cost responsibility for reliability-based interregional projects that are located solely
within one RTO according to the procedures specified in MISO’s filing.

Q: Why is MISO proposing to remove the flow-based cost allocation mechanisms for
CBBRPs from the JOA?

A: MISO is proposing to remove the flow-based cost allocation mechanisms for CBBRPs
because this allocation would conflict with the new Commission-approved local cost
allocation of BRPs in the MISO region pursuant to the MISO Tariff. Order No. 1000 states
that, to qualify for interregional cost allocation, an interregional project must be included in
the neighboring transmission planning regions’ respective regional plans for purposes of
regional cost allocation. MISO’s treatment of BRPs in its recently-revised, Order No.
1000-compliant Tariff dictates that BRPs no longer include any regionally allocated costs,
necessarily making CBBRPs ineligible for interregional cost allocation.

Q: Please explain further why CBBRPs are ineligible for interregional cost allocation.

A: In Order No. 1000, the Commission stated that an interregional project can only be eligible
for cost allocation between neighboring planning regions if it is selected in each planning
region’s respective regional transmission planning process for the purposes of cost
allocation.\textsuperscript{15} With the Commission’s ruling on March 22, 2013, effective June 1, 2013, the
cost of BRPs in MISO is now allocated solely to the pricing zone where the BRP is located,

\textsuperscript{15} See, e.g., Order No. 1000 at P 582.
and MISO is no longer able to select BRPs – of which CBBRPs are a subset – in the MTEP for the purposes of regional cost allocation. Therefore CBBRPs cannot satisfy Order No. 1000’s requirement that a project be selected in a planning region’s transmission expansion plan for purposes of cost allocation in order to be eligible for interregional cost allocation.

Q: **Does MISO have any other concerns regarding retaining the current cost allocation of CBBRPs as the PJM TOs propose?**

A: Yes. MISO has also determined that if a CBBRP were to be constructed entirely in PJM, under the current JOA MISO would have no way to allocate its share of that project within MISO, given that BRPs are now allocated entirely to the pricing zone in which the BRP is located.

Q: **Is MISO proposing to remove CBBRPs from the JOA entirely?**

A: No, MISO is not proposing to eliminate the CBBRP project type entirely. Rather, MISO is proposing to retain CBBRPs for scenarios where the affected Transmission Owners in MISO and PJM reach agreement on the funding of CBBRPs to address reliability issues in one or both RTOs, but not as an Order No. 1000 interregional project with interregional cost allocation that is approved by both regions with regional cost allocation. Similar to how the studies are conducted today, MISO and PJM will analyze the reliability issues and evaluate whether a CBBRP more efficiently and cost-effectively resolves the reliability issue for MISO and/or PJM. MISO’s proposed changes to the JOA specify that for a project to qualify as a CBBRP, it must (i) be determined by the Joint RTO Planning Committee (“JRPC”) to be needed to efficiently meet applicable reliability criteria and (ii) be a BRP or the equivalent project type under MISO’s and PJM’s tariffs. For CBBRPs that are tie-lines, MISO proposes that ownership and responsibility to construct CBBRPs
connecting the two RTOs will be based on the RTO boundaries between the connected
Transmission Owners or as otherwise determined by the connected Transmission Owners
in each region and that each RTO will recover its costs associated with CBBRPs pursuant
to its respective tariffs. In other words, MISO will recover CBBRP costs from the pricing
zone in which the tie-line is partially constructed, consistent with its cost allocation method
for BRPs, and PJM will recover its CBBRP costs pursuant to its tariff. For CBBRPs that
are located solely within either the MISO or PJM RTO, the constructing Transmission
Owner in one RTO will work with the Transmission Owner(s) in the other RTO that
has/have a reliability-based need that the CBBRP in a more efficient and cost-effective
manner addresses to determine by mutual agreement whether all or a portion of the
CBBRP should be paid for by the non-constructing Transmission Owner(s). Absent such
an agreement, the constructing Transmission Owner will have the option not to construct
the project if the proposed CBBRP is not needed to address a reliability issue in the pricing
zone (or, in the case of PJM, in the RTO) where the CBBRP would be located, or, if the
CBBRP is needed to address a reliability issue in the pricing zone (or in the case of PJM, in
the RTO) where it would be located, the Transmission Owner may opt to construct the
project or work with their RTO to identify an alternative Network Upgrade.

Q: Why is MISO proposing to retain the CBBRP project type?
A: MISO is proposing to remove the flow-based cost allocation for CBBRPs, but MISO is not
proposing to stop coordinating with PJM on reliability planning pursuant to the existing
procedures of the JOA. Pursuant to section 9.3.1 of the JOA, which is retained by this
compliance filing, each party commits to share information relating to its single party
planning, which must conform to applicable reliability requirements of the relevant RTO,
NERC, and applicable regional entities, as well as any applicable federal, state or provincial laws or regulations, on an ongoing basis as necessary for effective coordination between the RTOs. In addition, the Coordinated System Plan produced by MISO and PJM is required to integrate each party’s respective transmission expansion plan, including any identified reliability-related Network Upgrades. Retaining the CBBRP project type acknowledges that there could be opportunities to identify, through the coordinated planning process, a CBBRP as defined under MISO’s revised criteria, which could more efficiently address the reliability issues of the two regions than if they were to act individually.

Q: Please explain whether CBMEPs will also allow interregional consideration of benefits relating to reliability needs.

A: Yes, CBMEPs will also cover some projects that address reliability needs. Although the criteria a project must satisfy in order to qualify as a CBMEP are primarily economic, some projects that also address specific reliability needs may nonetheless qualify. For example, if a cross-border project begins as a CBBRP and after analysis is found to also qualify as a CBMEP, the project would be cost shared as a CBMEP. In addition, CBMEPs, which also qualify as MEPs under Attachment FF of MISO’s Tariff, must involve facilities with voltages of 345 kV or higher but may also include certain lower voltage facilities operating at 100 kV and above that are needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the 345 kV or higher facilities
of the project. These lower voltage facilities must, however, collectively constitute less than fifty percent of the combined project cost for the CBMEP.

Q: Do the PJM TOs agree with MISO’s proposed removal of cross-border cost allocation for CBBRPs from the JOA?

A: No. Although MISO and PJM agree on the interregional coordination procedures being submitted as part of their compliance filings, and MISO and the PJM TOs agree on the retention of CBMEPs for purposes of interregional cost allocation, the PJM TOs have not been open to any of MISO’s proposed revisions to the JOA’s existing CBBRP cost allocation provisions throughout MISO’s and the PJM TOs’ discussions regarding Order No. 1000’s interregional cost allocation requirements. The PJM TOs have maintained that position despite the Commission’s approval of the removal of regional cost allocation for BRPs in MISO. They do not agree with MISO’s position that the changes to the cost allocation of BRPs in MISO’s Tariff require removing the JOA’s existing CBBRP cost allocation mechanisms. Further, the PJM TOs have informed MISO that they do not agree with MISO’s position that the JOA’s provision of interregional cost allocation of CBMEPs, while terminating interregional cost allocation of CBBRPs, would be compliant with the requirements of Order No. 1000. MISO was not able to reach complete agreement with the PJM TOs on the preferred interregional cost allocation approach due largely to the current material differences in the regional cost allocation methods for solely reliability-based projects in MISO and PJM, which were not present when the existing CBBRP and CBMEP provisions were first implemented. As explained above, the

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16 See Attachment FF, section II.B.

17 See id.
Commission approved MISO’s reliance on MEPs and MVPs for purposes of meeting Order No. 1000’s regional cost allocation requirements, while the Commission approved PJM’s use of MEPs and BRPs for purposes of complying with such regional cost allocation requirements. MISO’s proposal recognizes these differences and attempts to find areas of commonality between the two regions. The common area in regional cost allocation methods between MISO and PJM is the MEP project category, considering that PJM does not have an equivalent of MISO’s MVPs, and MISO no longer has regional cost allocation for BRPs. This area of overlap in regional cost allocation methods, *i.e.* MEPs, is why MISO is proposing to use the existing CBMEP provisions of the JOA to comply with the interregional cost allocation requirements of Order No. 1000.

Despite engaging each other and each other’s stakeholders on numerous occasions, MISO and PJM use different bases for cost allocation. Because of the difficulties inherent to bridging these different approaches, MISO and the PJM TOs were unable to reach complete agreement regarding the cost allocation of interregional transmission projects. Notwithstanding, because the development of interregional cost allocation mechanisms is generally an iterative process, MISO will continue to coordinate with PJM and the PJM TOs, as the interregional planning process continues to evolve.

**B. Compliance with Order No. 1000’s Six Interregional Cost Allocation Principles**

**Q:** Do CBMEPs satisfy Order No. 1000’s requirements for interregional cost allocation?

**A:** Yes, CBMEPs satisfy all six of the interregional cost allocation principles set forth by the Commission in Order No. 1000. In addition, the Commission has previously found that CBMEPs employ a just and reasonable method of allocating costs.
1. Interregional Cost Allocation Principle 1: Costs Allocated Roughly Commensurate with Benefits

Q: Do CBMEPs satisfy cost allocation principle 1?

A: Yes. Cost allocation principle 1 requires that the cost of transmission facilities be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. The Commission has previously determined that CBMEPs employ a just and reasonable method of allocating costs. The JOA ensures that the allocation of costs of CBMEPs is roughly commensurate with the benefits created by these projects by allocating costs to MISO and PJM in proportion to the net present value of the total benefits calculated for each RTO as a result of the CBMEP. Under the JOA, CBMEPs utilize a benefit metric that calculates the change in Adjusted Production Cost (“APC”) and Net Load Payment (“NLP”) with and without the CBMEP for each RTO. The benefit metric weighs the APC benefit and the NLP benefit 70 percent and 30 percent, respectively. The ratio of the combined benefit metrics of MISO and PJM to the cost of the proposed facilities must be at least 1.25. Each RTO is therefore allocated CBMEP costs that directly correspond to the benefits calculated for it derived from the proposed facilities. Further, the use of a 1.25 or greater benefits-to-costs ratio requirement ensures that each RTO’s benefit in terms of production cost savings and congestion relief is large enough to justify the project.

2. Interregional Cost Allocation Principle 2: No Involuntary Allocation to Non-Beneficiaries

Q: Do CBMEPs satisfy cost allocation principle 2?
A: Yes. Cost allocation principle 2 requires that a transmission planning region that receives no benefit from an interregional transmission facility located in that region, either at present or in a likely future scenario, not be involuntarily allocated any of the costs of that transmission facility. CBMEPs fully comply with this requirement, as they must be selected both by MISO and PJM in their regional transmission planning processes. They must also be evaluated jointly pursuant to the JOA’s Coordinated System Plan process. These procedural considerations ensure that neither MISO nor PJM will be involuntarily allocated any of the costs of a CBMEP located within its respective region.


Q: Do CBMEPs satisfy cost allocation principle 3?

A: Yes. Cost allocation principle 3 requires that if a benefit-to-cost ratio threshold is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, it must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation. The Commission also states that such a threshold may not exceed 1.25 unless the Commission approves a higher ratio. Consistent with the Commission’s explicit allowance for a benefit-to-cost ratio threshold of 1.25 or less, MISO employs a benefit-to-cost ratio threshold of 1.25 for MEPs and CBMEPs, as previously discussed. The Commission also explicitly noted in a recent order that, in the context of MEPs, a benefit-to-cost ratio threshold of 1.25 is just and reasonable because it balances the economic uncertainty of transmission projects with the

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18 See JOA, section 9.3.5.2.(b).(x).

19 See JOA, section 9.4.3.
prospect of approving and constructing projects that provide benefits.\textsuperscript{20} The same logic applies in the context of CBMEPs.

4. **Interregional Cost Allocation Principle 4: Allocation Solely Within Transmission Planning Region Unless Those Outside Agree to Share Costs**

**Q:** Do CBMEPs satisfy cost allocation principle 4?

**A:** Yes. Cost allocation principle 4 requires that costs allocated for an interregional transmission facility be assigned only to transmission planning regions in which the transmission facility is located. Further, the Commission stated that interregional coordination must identify consequences for “third-party” transmission planning regions. However, FERC also recognized that it had previously required MISO and PJM specifically to develop a cross-border cost allocation method for facilities located in one RTO that benefit the other RTO as well and therefore exempted MISO and PJM from the portion of cost allocation principle 4 that forbids cost allocation to a transmission planning region in which a transmission facility is not located.\textsuperscript{21}

MISO further notes that, pursuant to Order No. 1000-A, any MISO Transmission Owner that withdraws from MISO will remain responsible for its share of the cost of any interregional project that is a MEP approved by MISO’s Board of Directors before the effective date of such Transmission Owner’s withdrawal, in accordance with MISO’s Transmission Owners Agreement (Article Five, Section II), and section III.A.2.f of Attachment FF of MISO’s Tariff.


\textsuperscript{21} Order No. 1000 at P 662.
5. Interregional Cost Allocation Principle 5: Transparency of Method for Determining Benefits and Identifying Beneficiaries

Q: Do CBMEPs satisfy cost allocation principle 5?

A: Yes. Cost allocation principle 5 requires that the cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed interregional transmission facility. The cost allocation process for CBMEPs is fully compliant with this principle. The cost allocation and benefit determination methods for CBMEPs are described in detail in section 9.4.3.1.2.1 of the JOA. These processes are also applied in the context of MISO’s and PJM’s Coordinated System Plan process, which means that stakeholders have the opportunity to review and provide input regarding these determinations via the Inter-regional Planning Stakeholder Advisory Committee (“IPSAC”). In addition, these determinations, as well as the underlying calculations and other analyses, are posted on each RTO’s interregional planning coordination web page for the IPSAC, and the resulting recommendations are included in the Coordinated System Plan, which is also posted on each RTO’s website pursuant to proposed section 9.1.1.3 of the JOA.


Q: Do CBMEPs satisfy cost allocation principle 6?

A: Yes. Cost allocation principle 6 states that public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation

\[22 \text{ See JOA, section 9.5.3.1.}\]
method for different types of interregional transmission facilities. Because it is proposing
only to use the CBMEP project type for purposes of interregional cost allocation, however,
this principle does not apply to MISO.

VII. Conclusion

Q: Does this complete your testimony?

A: Yes.
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. ) Docket No. ER13-___-000

AFFIDAVIT

STATE OF INDIANA
COUNTY OF HAMILTON

Jennifer Curran, being first duly sworn, deposes and says she is the same Jennifer Curran, whose Affidavit accompanies this Prepared Direct Testimony, that such testimony was prepared by her, that she is familiar with the contents thereof; and the facts set forth herein are true and correct to the best of her knowledge, information, and belief; and that she does adopt the same as her sworn testimony in this proceeding.

Jennifer Curran

SUBSCRIBED AND SWORN to me this 10th day of July, 2013.

Amy Jones
Notary Public for Madison County, Indiana

My Commission Expires: November 16, 2014