NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

November 20, 2009

VIA ELECTRONIC FILING

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

Re: *North American Electric Reliability Corporation*, Docket No. RM06-16-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d) (1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC") regulations seeking approval to remove three waivers in NERC Reliability Standard requirements. These waivers are: the "Scheduling Agent Waiver" in INT-003-2; the "Enhanced Scheduling Agent Waiver" in INT-003-2; and the "RTO Inadvertent Interchange Accounting Waiver" in BAL-006-1. These waivers were necessary to accommodate the operation of the Midwest Independent System Operator ("Midwest ISO" or "MISO") market in a multi-Balancing Authority environment, but are no longer necessary or relevant because the Midwest ISO is now a single Balancing Authority.

The proposed standards that remove references to the waivers are designated as: INT-003-3 — Interchange Transaction Implementation, and BAL-006-2 — Inadvertent Interchange, and are hereby submitted for approval by FERC.

The proposed standards were approved by the NERC Board of Trustees on November 5, 2009. NERC requests that the retirement of the superseded standards (INT-003-2 and BAL-006-1) and the implementation of the proposed standards INT-003-3 and BAL-006-2 be made effective immediately upon FERC approval.

NERC's petition consists the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining the revision of the standards to remove the waivers;
- The redline of the proposed Revised Standards INT-003-3 and BAL-006-2 to INT-003-2 and BAL-006-1 (**Exhibit A)**; and
- The complete development record of the proposed standard revisions (**Exhibit B)**.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket No. RM06-16-000)**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF TWO RELIABILITY STANDARDS REVISIONS TO WITHDRAW MISO WAIVERS

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November 20, 2009

TABLE OF CONTENTS

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission ("FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, revision of two FERC-approved NERC Reliability Standards, BAL-006-1 and INT-003-2, to remove Midwest Independent System Operator ("Midwest ISO" or "MISO") waivers, proposed as INT-003-3 and BAL-006-2.

The NERC Board of Trustees approved the withdrawal of the "Scheduling Agent Waiver" and the "Enhanced Scheduling Agent Waiver" from INT-003-2, and the "RTO Inadvertent Interchange Accounting Waiver" from BAL-006-1 on November 5, 2009. NERC requests that FERC approve the revised Reliability Standards, designated as INT-003-3 and BAL-006-2, effective immediately after approval in accordance with FERC's procedures. Because no changes are proposed to the existing FERC-approved requirements in INT-003-2 and BAL-006-1, NERC requests that the approved Violation Risk Factors and Violation Severity Levels for the requirements in the existing standards be carried forward to the proposed versions of the standards that are the subject of this filing.

Exhibit A to this filing sets forth the Reliability Standards. **Exhibit B** contains the complete development record of the revised Reliability Standards. NERC also is filing this petition for withdrawal of MISO waivers and approval of the revised standards with governmental authorities in Canada.

[1] NERC has been certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").
[2] 16 U.S.C. 824o.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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President and Chief Executive Officer
David N. Cook*
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*Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

Rebecca J. Michael*
Assistant General Counsel
Holly A. Hawkins*
Attorney
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III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[3] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an electric reliability organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215 states that all users, owners and operators of the bulk power system in the United States will be subject to FERC-approved Reliability Standards.

[3] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005) (to be codified at 16 U.S.C. § 824o).

b. Basis for Removal of Waivers from Reliability Standards

Section 39.5(a) of FERC's regulations requires NERC to file with FERC for its approval each Reliability Standard that NERC proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that NERC proposes to be made effective. FERC has the regulatory responsibility to approve Reliability Standards that protect the reliability of the bulk power system. In implementing its responsibility to review, approve and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4]

When evaluating proposed Reliability Standards, FERC is expected to give "due weight" to the technical expertise of the ERO. Order No. 672 provides guidance on the factors FERC will consider when determining whether proposed Reliability Standards meet the statutory criteria.[5]

c. Reliability Standards Development Procedure

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which is incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, FERC found that NERC's proposed rules provide for

[4] Section 215(d)(2) of the FPA, to be codified at 16 U.S.C. § 824o(d)(2) (2000).
[5] *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs.*, ¶ 31,204 at PP 320-36 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards.[6]

The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard for submission to FERC.

IV. BAL-006-2

FERC approved Reliability Standard BAL-006-1 in Order No. 693.[7] In Section VI of this filing, NERC explains the need for and development of the revised version of the standard presented for approval in this filing.

Set forth below in Section VII are the stakeholder ballot results and a discussion regarding how stakeholder comments were considered and addressed by the team assembled to address the removal of the MISO waiver in the BAL-006-2 standard. The complete development record for the revised standard is set forth in **Exhibit B**. **Exhibit B** includes the Standard Authorization Request ('SAR"), the response to the request, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and how those comments were considered.

[6] Order No. 672 at PP 268, 270.
[7] *See* Order No. 693 at PP 439, 444, and Appendix A.

V. INT-003-3

FERC approved Reliability Standard INT-003-2 in Order No. 693.[8] In Section VI, below, NERC explains the need for and development of the revised version of the standard presented for approval in this filing.

Set forth below in Section VII are the stakeholder ballot results and an explanation regarding how stakeholder comments were considered and addressed by the team assembled to address the removal of the MISO waivers in the INT-003-2 standard. The complete development record for the revised standards is set forth in **Exhibit B**. **Exhibit B** includes the SAR, the response to the request, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and how those comments were considered.

VI. JUSTIFICATION FOR APPROVAL OF PROPOSED REVISIONS

The stated purposes of Reliability Standards INT-003-2 and BAL-006-1, respectively, are:

> INT-003-2
> To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.
>
> BAL-006-1
> This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

These standards support the reliability principles that 1) interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably

[8] *See* Order No. 693 at PP 833 and 838 and Appendix A.

under normal and abnormal conditions as defined in the NERC Standards, and 2) information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Three waivers to NERC standard requirements – the "Scheduling Agent Waiver" and the "Enhanced Scheduling Agent Waiver" from INT-003-2, and the "RTO Inadvertent Interchange Accounting Waiver" associated with BAL-006-1, were necessary to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. These waivers were first approved by the NERC Operating Committee in 2002, 2003, and 2004, respectively, and were carried forward into the Reliability Standards originally approved by FERC in Order No. 693.

The Midwest ISO is now a single Balancing Authority, and these waivers are no longer necessary. During its April 15, 2009 and April 16, 2009 meeting, the NERC Standards Committee approved a SAR for removing waivers in the current NERC standards associated with accommodating the operation of the Midwest ISO market in a multi-Balancing Authority environment. More specifically, the following changes to the standards were proposed:

> • References to the Midwest ISO should be removed from the "Scheduling Agent Waiver" associated with INT-003-2 – Interchange Transaction Implementation.
>
> • The "Enhanced Scheduling Agent Waiver" associated with INT-003-2 should be retired.
>
> • References to the Midwest ISO should be removed from the "RTO Inadvertent Interchange Accounting Waiver" associated with BAL-006-1 – Inadvertent Interchange.

The proposed changes to these standards do not reduce their effectiveness in achieving the stated reliability objectives; in fact, they will be clearer and more consistent for all applicable entities as a result of these changes.

VII. SUMMARY OF RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

On April 15, 2009, the NERC Standards Committee accepted a SAR to withdraw three waivers that accommodated the operation of the Midwest ISO market in a multi-Balancing Authority environment. The draft SAR and the proposed standards changes were posted for comment from April 22, 2009 through June 5, 2009.

The drafting team received 16 sets of comments from approximately 60 people representing more than 30 organizations from nine of the 10 Industry Segments. Stakeholders agreed with the proposed modifications to BAL-006-2 and INT-003-3. Stakeholders did not identify any associated business practices for consideration.

One commenter suggested that the SAR drafting team also consider the removal of a third waiver reflected in the INT-003-2 standard - MISO Energy Flow Information Waiver. The waiver was also originally requested and approved to implement a multi-control area energy market. The Midwest ISO considered recommending the removal of the MISO Energy Flow Information Waiver, but determined this waiver is still applicable because the intent of the waiver is to allow generation to load transfers to be uploaded to the Interchange Distribution Calculator ("IDC") in lieu of eTags. The Midwest ISO determined that this information is still needed in the IDC to properly account for impacts on internal and external flowgates. As a result, no changes were made to the SAR with

respect to this waiver. The drafting team recommended that the NERC Standards Committee move the Standards forward for a pre-ballot period and subsequent balloting of the standards.

The initial ballot was conducted from August 27, 2009 through September 8, 2009 and achieved a quorum of 85.28 percent with a weighted affirmative approval of 99.62 percent. There was one negative ballot submitted for the initial ballot. Because the negative vote did not include a comment, the results were final and no recirculation ballot was required. No additional changes were proposed for any of the requirements in the two standards proposed for approval. The standards were approved by the NERC Board of Trustees on November 5, 2009.

VIII. CONCLUSION

NERC requests that FERC approve the proposed revised NERC Reliability Standards, BAL-006-2 and INT-003-3, removing the MISO waivers, as set out in **Exhibit A**, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC's regulations. Because the removal of the waivers does not affect the other standard requirements, NERC proposes that the currently effective Violation Severity Levels and Violation Risk Factors be carried forward intact in the revised standards. NERC requests that these revised standards be made effective immediately upon issuance of FERC's order in this proceeding.

Respectfully submitted,

/s/ Holly A. Hawkins

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 20th day of November, 2009.

/s/ Holly Hawkins
Holly Hawkins
Attorney for North American Electric Reliability Corporation

Exhibit A

Reliability Standards
INT-003-3 — Interchange Transaction Implementation
and
BAL-006-2 — Inadvertent Interchange

A. Introduction

1. Title: **Interchange Transaction Implementation**

2. Number: INT-003-3

3. Purpose:

To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. Applicability

4.1. Balancing Authorities.

5. Effective Date: First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. (*Violation Risk Factor: Medium*)

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: (*Violation Risk Factor: Lower*)

R1.1.1. Interchange Schedule start and end time. (*Violation Risk Factor: Lower*)

R1.1.2. Energy profile. (*Violation Risk Factor: Lower*)

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. (*Violation Risk Factor: Medium*)

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule's start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority's ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Balancing Authority shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
R1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.2	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.2	The sending or receiving Balancing Authority experienced	The sending or receiving Balancing Authority experienced	The sending or receiving Balancing Authority experienced	The sending or receiving Balancing Authority experienced

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

E. Regional Differences

MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
3	To be determined.	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver	Revised
3	November 5, 2009	Adopted by the NERC Board of Trustees	Revised

A. Introduction

1. **Title:** **Interchange Transaction Implementation**

2. **Number:** INT-003-~~2~~3

3. **Purpose:**

   To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. **Applicability**

   4.1. Balancing Authorities.

5. **Effective Date:** ~~January 1, 2007~~First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. (*Violation Risk Factor: Medium*)

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: (*Violation Risk Factor: Lower*)

R1.1.1. Interchange Schedule start and end time. (*Violation Risk Factor: Lower*)

R1.1.2. Energy profile. (*Violation Risk Factor: Lower*)

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. (*Violation Risk Factor: Medium*)

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule's start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority's ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Balancing Authority shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

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2. Violation Severity Levels:

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
R1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.

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R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.1.2	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.2	The sending or receiving Balancing Authority experienced one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

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E. Regional Differences

1. MISO Scheduling Agent Waiver dated November 21, 2002.
2. MISO Enhanced Scheduling Agent Waiver dated July 16, 2003.
3. MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
3	To be determined.	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver	Revised

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A. Introduction

1. Title: **Inadvertent Interchange**

2. Number: BAL-006-2

3. Purpose:

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. Applicability:

4.1. Balancing Authorities.

5. Effective Date: First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R4.1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following

month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

E. Regional Differences

1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	To be determined.	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver	Revision
2	November 5, 2009	Adopted by the NERC Board of Trustees	Revision

A. Introduction

1. **Title:** **Inadvertent Interchange**

2. **Number:** BAL-006-~~1~~2

3. **Purpose:**

   This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. **Applicability:**

   4.1. Balancing Authorities.

~~5.~~

~~5.~~**Effective Date:** ~~May 1, 2006~~ First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

~~This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.~~

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B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

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R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

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R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)

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R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

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R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

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R4.1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

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R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

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R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

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R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

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R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

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C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business

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R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.

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R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

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E. Regional Differences

1. ~~MISO RTO~~ Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004~~. This regional difference will be extended to~~ includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	To be determined.	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver	Revision

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Exhibit B

Record of Development for INT-003-3 — Interchange Transaction Implementation; BAL-006-2 — Inadvertent Interchange

Project 2009-18
Withdraw Three Midwest ISO Waivers

Status:
The SAR for the removal of three of MISO's waivers from BAL-006-2 and INT-003-3, as well as the proposed revisions to those standards and Implementation Plan were approved by the Ballot Pool. The standards were approved by the NERC Board of Trustees on November 5, 2009 and will be submitted to FERC for approval.

Background:
During their April 15-16, 2009 meeting the Standards Committee approved a SAR for removing waivers in the current NERC Standards associated with accommodating the operation of the Midwest ISO market in a multi-Balancing Authority environment. These waivers are no longer needed by the Midwest ISO now that the Midwest ISO is a Balancing authority:

• References to the Midwest ISO should be removed from the "Scheduling Agent Waiver" associated with INT-003-2 – Interchange Transaction Implementation.

• The "Enhanced Scheduling Agent Waiver" associated with INT-003-2 should be retired.

• References to the Midwest ISO should be removed from the "RTO Inadvertent Interchange Accounting Waiver" associated with BAL-006-1 – Inadvertent Interchange.

The purpose/industry need is to provide clarity in the applicability of the standard.

Draft	Action	Dates	Results	Consideration of Comments
SAR for Removal of three of MISO's Waivers from BAL-006-2 and INT-003-3 Draft SAR Version 1 **(13)** BAL-006-2 Clean **(14)** | Redline to last approval **(15)** INT-003-3 Clean **(16)** | Redline to last approval **(17)** **Supporting Materials:** Implementation Plan **(18)** MISO Waivers Proposed for Removal **(19)**	Initial Ballot Info>> **(20)** | Vote>>	08/27/09 - 09/08/09 (closed)	Summary>> **(21)** Full Record>> **(22)**	
	Pre-ballot Review Info>> **(12)** | Join>>	07/27/09 - 08/27/09 (closed)		

SAR for Removal of three of MISO's Waivers from BAL-006-2 and INT-003-3 Draft SAR Version 1 **(2)** BAL-006-2 Clean **(3)** | Redline to last approval **(4)** INT-003-3 Clean **(5)** | Redline to last approval **(6)** **Supporting Materials:** Comment Form (Word) **(7)** Implementation Plan **(8)** MISO Waivers Proposed for Removal **(9)**	Comment Period Info>> **(1)** Submit Comments>>	04/22/09 - 06/05/09 (closed)	Comments Received>> **(10)**	Consideration of Comments>> **(11)**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
April 22–June 5, 2009

Now available at: http://www.nerc.com/filez/standards/Project2009-18_Withdraw_Three_MISO_Waivers.html

Project Name:
2009-18 — Withdraw Three Midwest ISO Waivers

Due Date and Submittal Information:
The comment period is open **until 8 p.m. EDT on June 5, 2009**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Project2009-18_Withdraw_Three_MISO_Waivers.html

Content for Comment Period:
- A proposed Standard Authorization Request (SAR) for the removal of three Midwest ISO waivers from BAL-006-1 and INT-003-2
- Clean and redline versions of BAL-006-2 — Inadvertent Interchange
- Clean and redline versions of INT-003-3 — Interchange Transaction Implementation

Other Materials Posted:
- Document listing the three Midwest ISO waivers
- Implementation plan

Project Background:
The three waivers identified below were drafted to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. Now that the Midwest ISO is a Balancing Authority, these waivers are no longer needed by the Midwest ISO. Removing these waivers (or references to the Midwest ISO) will make the standards clearer.

- Inadvertent Accounting Waiver from BAL-006 — Inadvertent Accounting
- Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation
- Enhanced Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation

The scope of this project is limited to the removal of the three identified waivers — there are no conforming changes to the applicability, requirements, measures or compliance elements of the standard.

Applicability of Standards in Project:
- Balancing Authorities

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Withdraw 3 Midwest ISO Waivers
Request Date	April 2, 2009
SC Approval Date	April 15, 2009

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Terry Bilke	☐	New Standard
Primary Contact	Midwest ISO	☒	Revision to existing Standards INT-003-2 BAL-006-1
Telephone Fax	317-249-5463 317-249-5358	☐	Withdrawal of existing Standard
E-mail	tbilke@midwestiso.org	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

Three of the waivers in the current NERC Standards were drafted to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. Now that the Midwest ISO is a Balancing authority, these waivers are no longer needed by the Midwest ISO. Removing these waivers (or references to the Midwest ISO) will make the standards clearer.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

Remove unnecessary information from the standards and eliminate confusion.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

References to the Midwest ISO should be removed from the "Scheduling Agent Waiver" associated with INT-003-2 – Interchange Transaction Implementation.
The "Enhanced Scheduling Agent Waiver" associated with INT-003-2 should be retired.

References to the Midwest ISO should be removed from the "RTO Inadvertent Interchange Accounting Waiver" associated with BAL-006-1 – Inadvertent Interchange.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) See the "brief description".

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
INT-003-2	Waivers mentioned in this standard.
BAL-006-1	Waivers mentioned in this standard.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

A. Introduction

1. Title: **Inadvertent Interchange**

2. Number: BAL-006-2

3. Purpose:

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. Applicability:

4.1. Balancing Authorities.

5. Effective Date: First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R4.1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional

Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

E. Regional Differences

1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	To be determined.	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver	Revision

A. Introduction

1. Title: **Inadvertent Interchange**

2. Number: BAL-006-~~1~~2

3. Purpose:

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. Applicability:

4.1. Balancing Authorities.

5.

~~5.~~**Effective Date:** ~~May 1, 2006~~ First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

~~This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.~~

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R4.1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

E. Regional Differences

1. ~~MISO RTO~~ Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004~~. This regional difference will be extended to~~ includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	To be determined.	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver	Revision

A. Introduction

1. Title: **Interchange Transaction Implementation**

2. Number: INT-003-3

3. Purpose:

To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. Applicability

4.1. Balancing Authorities.

5. Effective Date: First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. (*Violation Risk Factor: Medium*)

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: (*Violation Risk Factor: Lower*)

R1.1.1. Interchange Schedule start and end time. (*Violation Risk Factor: Lower*)

R1.1.2. Energy profile. (*Violation Risk Factor: Lower*)

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. (*Violation Risk Factor: Medium*)

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule's start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority's ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Balancing Authority shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
R1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.2	The Balancing Authority	The Balancing Authority	The Balancing Authority	The Balancing Authority

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.2	The sending or receiving Balancing Authority experienced one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

E. Regional Differences

MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
3	To be determined.	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver	Revised

A. Introduction

1. Title: **Interchange Transaction Implementation**

2. Number: INT-003-~~2~~3

3. Purpose:

To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. Applicability

4.1. Balancing Authorities.

5. Effective Date: ~~January 1, 2007~~First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. (*Violation Risk Factor: Medium*)

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: (*Violation Risk Factor: Lower*)

R1.1.1. Interchange Schedule start and end time. (*Violation Risk Factor: Lower*)

R1.1.2. Energy profile. (*Violation Risk Factor: Lower*)

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. (*Violation Risk Factor: Medium*)

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule's start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority's ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Balancing Authority shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
R1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.1.2	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.2	The sending or receiving Balancing Authority experienced one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

E. Regional Differences

~~1.MISO Scheduling Agent Waiver dated November 21, 2002.~~

~~1.MISO Enhanced Scheduling Agent Waiver dated July 16, 2003.~~

~~2.~~MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
3	To be determined.	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver	Revised

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for SAR and Proposed Modifications to Remove Three MISO Waivers from BAL-006 and INT-003 (Project 2009-18)

Please **DO NOT** use this comment form. Please use the electronic comment form located at the link below to submit comments on the proposed SAR for removal of three of MISO's Waivers from BAL-006 and INT-003, and for the proposed revisions to those standards. Comments must be submitted by **June 5, 2009**. If you have questions please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

http://www.nerc.com/filez/standards/Project2009-18_Withdraw_Three_MISO_Waivers.html

Background Information:
The three waivers identified below were drafted to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. Now that the Midwest ISO is a Balancing Authority, these waivers are no longer needed by the Midwest ISO. Removing these waivers (or references to the Midwest ISO) will make the standards clearer.

- Inadvertent Accounting Waiver from BAL-006 — Inadvertent Accounting
- Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation
- Enhanced Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation

The scope of this project is limited to the removal of the three identified waivers — there are no conforming changes to the applicability, requirements, measures or compliance elements of the standard.

The requester would like to receive industry comments on the SAR and proposed modifications to BAL-006 and INT-003.

***Please use the electronic comment form to submit your final responses to NERC.**

1. The SAR is limited to removing the identified MISO waivers from BAL-006-1 and INT-003-2. Do you agree that these waivers should be removed since MISO is now operating as its own Balancing Authority and the conditions under which the waivers were approved are no longer applicable? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

2. Are you aware of any associated business practices that we should consider with this SAR? If yes, please explain in the comment area.

☐ Yes

☐ No

Comments:

3. Do you agree with the proposed modifications to BAL-006-2 and INT-003-3? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

4. If you have any other comments on the SAR or proposed modifications to BAL-006-2 or INT-003-3 that you haven't provided in response to the previous questions, please provide them here.

Comments:

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Implementation Plan for Project 2009-18

This project involves the removal of MISO Waivers from the following two standards:

BAL-006-2 — Inadvertent Interchange

INT-003-3 — Interchange Transaction Implementation

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the revisions to these two standards can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no new or revised definitions and no proposed revisions to any other standards as part of this project.

Compliance with Standard

The requirements in BAL-006-2 and in INT-003-3 apply solely to entities registered to perform the Balancing Authority function.

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard. Because the proposed modification is the removal of a waiver that is no longer needed, the proposed effective date does not anticipate that the affected entities will need any time to prepare for the revision.

The revisions to the standards should become effective as early as practical, and the following dates have been proposed:

> The proposed revisions to both standards should become effective on the first day of the first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

MISO Waivers Proposed for Removal:

RTO Inadvertent Interchange Accounting

(Approved by the NERC Operating Committee March 23–25, 2004)

This waiver was carried over with the development of Version 0 standards into BAL-006.

Organization

The control area participants of the Midwest ISO

Operating Policy

Standards
Policy 1F, Inadvertent Interchange Standard

Requirements
Policy 1G 1.1. — Control Surveys (AIE Survey)
Policy 1G2.2. — Inadvertent Interchange Summaries (Surveys)

Explanation

NERC Policy 1.F "Inadvertent Interchange Standard" speaks only of control areas accounting for Inadvertent Interchange. The policy was written before the advent of RTOs.

The CONTROL AREA participants request that the RTO be given an Inadvertent Interchange account. This will support the RTO in meeting its FERC-directed market obligations.
The current model for an LMP market requires financial settlement of all energy receipts and deliveries. This means control areas operating within this market will pay for (or be paid for) their Inadvertent Interchange. Financial settlement of inadvertent is allowed under Policy 1.F. 5.2. (other payback methods) and the *Financial Inadvertent Settlement Waiver*.

The approved *Enhanced Scheduling Agent Waiver* authorizes the RTO to act as a sink or source Control Area in order to manage transactions into, out of, or through the RTO. Approval of this *Inadvertent Interchange Waiver* allows the RTO to manage any financially settled net imbalance with the Interconnection.

Continued Responsibilities

Control areas will continue to perform all the traditional Inadvertent Accounting tasks as outlined in NERC Policy 1.F. and Appendix 1.F. In other words, the RTO control areas will continue to:

- Verify daily Actual Net Interchange with their adjacent control areas and if there are differences, resolve them within the time frame in NERC Policy 1.F.
- Operate to "equal and opposite" Net Actual Interchange with their adjacent control areas.
- Operate to an "equal and opposite" Scheduled Net Interchange with the RTO, consistent with the current *Scheduling Agent Waiver*.
- Verify daily Scheduled Net Interchange with the RTO and if there are differences, resolve them within the time frame in NERC Policy 1.F.
- Report their monthly Inadvertent Interchange data to their respective Regions.

The RTO will also continue to perform all the Inadvertent Accounting tasks as an intermediate control area (as specified in the *Scheduling Agent Waiver*) and source or sink control area (as specified in the *Enhanced Scheduling Agent Waiver*) including:

- Verify daily Scheduled Net Interchange with the RTO control areas and adjacent control areas, and if there are differences, resolve them within the time frame in NERC Policy 1.F.

- Operate to an "equal and opposite" Scheduled Net Interchange with the RTO control areas and adjacent control areas.
- Operate so that the Scheduled Net Interchange of the RTO (Sum of the Scheduled Net Interchanges with the RTO control areas and adjacent control areas) is zero (or equal to the RTO Inadvertent Payback as outlined below).

New Responsibilities

Financially settled Inadvertent would be removed from the control areas' balances. The RTO inadvertent account would reflect the net RTO imbalance with the Interconnection. In order to accomplish this, the RTO would add "equal and opposite" schedules with the RTO control areas after the settlement. The net of these "settlement" schedules will be zero.

As requested by the NERC Resources Subcommittee, the RTO will report its Inadvertent Interchange balance to ECAR. RTO reporting will be consistent with the requirements and timelines for control areas outlined in Policy 1F. In addition, the RTO will maintain records of Inadvertent Interchange financially settled with each control area and will provide AIE data (pre and post settlement) for any surveys or formal data requests.

The RTO will manage and pay back its net Inadvertent Interchange balance following NERC policy. Inadvertent payback will be initiated based on an objective and publicly available process that is triggered on balances exceeding statistical norms (allows normal "breathing" of balances). Inadvertent Payback will be done during periods and in amounts such that payback will not burden others or interfere with time corrections. Financial gain will not factor into the decision to payback or recover Inadvertent Interchange.

Current Operating Reliability

This waiver request is to accommodate after-the-fact transfer of financially settled Inadvertent Interchange. The waiver has no impact on real-time balancing performed by the control areas. The RTO will always operate with a "net zero" Scheduled Interchange. The waiver will not affect the way the RTO control areas perform or calculate CPS and DCS.

The Control Area Participants believe this waiver promotes reliability for two reasons:

- It eliminates the incentive for burdening the Interconnection by manipulating imbalances for financial gain (taking in inadvertent during periods of high price and returning it when prices subside). This is consistent with NERC Operating Committee's charge to the Joint Inadvertent Interchange Task Force (JIITF) and moves the JIITF's recommendations closer to realization.
- Increased transparency as the influence of RTO's markets on the Interconnection will be apparent through this separate RTO Inadvertent Interchange account. Any scheduling or process errors would be traceable through this account.

Scheduling Agent Waiver

(Approved by the NERC Operating Committee on November 21, 2002)

This waiver was carried over with the development of Version 0 standards into INT-003.

Organization

The Control Area participants of:

- Alliance RTO
- Midwest ISO
- Southwest Power Pool
- Grid South

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs. The participants are requesting a Waiver of specific provisions of NERC Policy 1, "Generation Control and Performance," and Policy 3, "Interchange," to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of a SCHEDULING AGENT:

SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting. The following specific sections of NERC Policy 1 Version 1a, "Generation Control and Performance," and Policy 3, Version 4, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Standards

Policy 1

- Policy 1F, "Inadvertent Interchange Standard"

Requirements

Policy 1

- 1G 1.1 — Control Surveys (AIE Survey)

Policy 3

- 3A 4 — Interchange Transaction Implementation (Assessment)
- 3A 6 — Interchange Transaction Implementation (Implementation)
- 3B 4 — Interchange Schedule Implementation (Confirmation)

Explanation

The SCHEDULING AGENT would be the single point of contact for all external, non-participating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Intra-RTO TRANSACTIONS would be handled with the SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES. The RTO CONTROL AREA participants propose to:

1. Designate their RTO as a SCHEDULING AGENT to act on their behalf with all ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.
2. Include the SCHEDULING AGENT in the SCHEDULING PATH of all INTERCHANGE TRANSACTIONS effectively placing the RTO SCHEDULING AGENT in the role of an INTERMEDIARY CONTROL AREA with respect to INTERCHANGE TRANSACTION management.
3. Manage any "scheduling error" attributable to the SCHEDULING AGENT and internalize this scheduling error into the INADVERTENT INTERCHANGE accounts of the participating CONTROL AREAS.
4. Include the SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to an INTERMEDIARY CONTROL AREA. By establishing a SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:
    a. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will:
        i. Allow the participant RTO CONTROL AREAS to implement INTERCHANGE SCHEDULES directly with the SCHEDULING AGENT, significantly reducing the scheduling, coordination and checkout contacts of the participants.
        ii. Allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.
    b. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.
    c. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

Enhanced Scheduling Agent Waiver

(Approved by the NERC Operating Committee July 16–17, 2003)

This waiver was carried over with the development of Version 0 standards into INT-003.

Organization

The Control Area participants of:

- Midwest ISO

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs. The participants are requesting a Waiver of specific provisions of NERC Policy 3, "Interchange," to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of an ENHANCED SCHEDULING AGENT:

ENHANCED SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting.

The following specific sections of NERC Policy 3, Version 4, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Policy 3

- 3A 4 — Interchange Transaction Implementation (Assessment)
- 3A 6 — Interchange Transaction Implementation (Implementation)
- 3B 4 — Interchange Schedule Implementation (Confirmation)

Explanation

The ENHANCED SCHEDULING AGENT would be the single point of contact for all external, nonparticipating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Through TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. Into or Out Of TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the SINK or SOURCE CONTROL AREA, respectively. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES. The RTO CONTROL AREA participants propose to:

5. Designate their RTO as an ENHANCED SCHEDULING AGENT to act on their behalf with all external ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.
6. Include the Enhanced Scheduling Agent in the Scheduling Path of all Interchange Transactions in the role of Control Area (Intermediary, Source, or Sink as appropriate) with respect to Interchange Transaction management.
7. Include the ENHANCED SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to a CONTROL

AREA. By establishing an ENHANCED SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:

a. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the ENHANCED SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.

b. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.

c. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

d. The CONTROL AREAS within a RTO served by a ENHANCED SCHEDULING AGENT would be transparent to a transmission customer as the customer reserves transmission service and submits an energy schedule for pass-through transactions across said RTO.

e. By simplifying the transaction implementation process for both participant and non-participant CONTROL AREAS, automation of INTERCHANGE confirmation, scheduling and checkout with the ENHANCED SCHEDULING AGENT becomes achievable.

The proposal simplifies the transaction tagging process for market participants in that there is no longer a need to designate a specific CONTROL AREA contract path within or through the RTO where there may, in fact, be several parallel contract paths possible. The specific scheduling processes implemented between participating CONTROL AREAS within the RTO are internalized and transparent to the market, but will not violate any reliability criteria.

Current Operating Reliability Implications

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 3A4

The CONTROL AREA Assesses:

- Transaction start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- Scheduling Path (proper connectivity of ADJACENT CONTROL AREAS)

Conditions:

The Control Area Participants will allow the RTO Scheduling Agent to assess proper connectivity on the Scheduling Path.

Policy 3A6
Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

Conditions:
The applicants clarify that the Enhanced Scheduling Agent shall assume the role and responsibilities of the INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with regard to Policy 3, and the individual RTO's Control Areas do not appear in the Scheduling Path on the tag. The RTO's Control Areas will not incorporate these transactions into a schedule in their EMS.

Policy 3B4
INTERCHANGE SCHEDULE confirmation and implementation. The RECEIVING CONTROL AREA is responsible for initiating the CONFIRMATION and IMPLEMENTATION of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

INTERCHANGE SCHEDULE agreement. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:

- Interchange Schedule start and end time
- Ramp start time and rate
- Energy profile

Conditions:
The obligation with respect to confirmation and implementation of INTERCHANGE SCHEDULES under Policy 3B 4 shall be satisfied by the confirmation of all schedules with the Scheduling Agent. The Scheduling Agent shall assume the role and responsibilities that would otherwise be considered that of an INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with respect to all transactions and schedules involving the RTO or its Control Areas.

Additional Conditions

The Operating Committee approved this waiver on July 16, 2003 with the following condition:

> "With NERC and appropriate regional representation, audit and confirm the Midwest ISO's readiness to perform the functions detailed in the enhanced scheduling agent and energy flow information waivers before they go into effect."

Individual or group. (16 Responses)
Name (10 Responses)
Organization (10 Responses)
Group Name (6 Responses)
Contact Organization (6 Responses)
Question 1 (15 Responses)
Question 1 Comments (16 Responses)
Question 2 (15 Responses)
Question 2 Comments (16 Responses)
Question 3 (15 Responses)
Question 3 Comments (16 Responses)
Question 4 (0 Responses)
Question 4 Comments (16 Responses)

Individual
Edward C. Stein
Self-Retired
Yes
Yes
This is more of a reliability practice than a business practice. It is my understanding that MISO has not accepted the reliability role of Resource Planner (RP), similar to PJM, even though they have accepted the role of Balancing Authority (BA) and run one of the largest electricity Markets in America. The only difference that I see is that MISO runs an energy only market where as PJM runs both an energy market and a capacity market. It very well may be that MISO is moving towards two markets, energy and capacity. My concern is that given the time that it took MISO to become a BA, it will take even longer for MISO to move towards two markets and the role of RP. I recommend that the Drafting Team develop a separate SAR to address the RP issue in order to speed the process of eliminating the MISO waivers since they truly are a BA.
Yes
Individual
Greg Rowland
Duke Energy
Yes
No
Yes
Individual
Jeffrey V Hackman
Ameren Services
No
While the stated purpose is "limited to removing MISO waivers", the redline for the the INT shows in the revision block that VRF and VSL will be modified. This looks like a back door revision under this SAR language.

No
No
See response to Q1
Individual
James H. Sorrels, Jr.
American Electric Power
Yes
No
Yes
Individual
Joe O'Brien
NIPSCO
Yes
No
Yes
Group
Northeast Power Coordinating Council
Northeast Power Coordinating Council
We don't have any comments at the present time.
Individual
Alan Gale
City of Tallahassee
Yes
Yes
Yes
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
No
Yes
Group
Bonneville Power Administration
BPA Transmission Reliability Program
Yes

No
Yes
Individual
Dan Rochester
Ontario IESO
Yes
No
Yes
Group
NERC Standards Review Subcommittee
Midwest Reliability Organization
Yes
No
Yes
N/A
Group
Public Service Commission of South Carolina
Public Service Commission of South Carolina
Yes
No
Yes
Group
PJM
NERC and Regional Coordination
Yes
No
Yes
Group
SERC OC Standards Review Group
Entergy
Yes
No
Yes
Individual
Jason Marshall

Midwest ISO
Yes
No
Yes
Individual
Doug Hohlbaugh
FirstEnergy
Yes
No
Yes
FirstEnergy agrees that the BAL-006 waiver is obsolete given the Amended BA Agreement and matrix whereby MISO alone calculates and records its own inadvertent interchange and verifies net interchange with its neighbors. Absent the Amended BA Agreement/Matrix, the waiver was needed to give MISO an inadvertent account for its market. The waiver also specified that control areas within MISO would operate to net scheduled interchange with MISO, which is no longer the case under the Amended BA Agreement/Matrix. FirstEnergy also supports the two identified waivers proposed for removal from the INT-003 standard as they are also unneeded since the Amended BA Agreement/Matrix assigns interchange scheduling solely to MISO. FirstEnergy ask that the SAR DT also consider the removal of the third waiver reflected in the INT-003 standard - MISO Energy Flow Information Waiver. The Waiver was originally requested/approved to implement a multi-Control Area Energy Market. Even though the MISO Energy Flow Information Waiver says that it should also apply in the event that Control Areas in the RTO are combined into fewer Control Areas or into one Control Area it seems inconceivable that one would need a multi-control area waiver for one consolidated control area. We ask that the SAR DT reconsider the need for the MISO Energy Flow Information Waiver and provide reason for its continued use if deemed appropriate.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on SAR and Proposal to Withdraw Three Midwest ISO Waivers from BAL-006 and INT-003 (Project 2009-18)

The Requester and Drafting Team thanks all commenters who submitted comments on the SAR, the proposed revisions to the BAL-006-2 — Inadvertent Interchange standard, INT-003-3 — Interchange Transaction Implementation standard, and the associated implementation plan. These documents were all posted for a 45-day public comment period from April 22, 2009 through June 5, 2009. The stakeholders were asked to provide feedback on the documents through a special electronic comment form. There were 16 sets of comments, including comments from approximately 60 different people from more than 30 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

In this "Consideration of Comments" document stakeholder comments have been arranged so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

http://www.nerc.com/filez/standards/Project2009-18_Withdraw_Three_MISO_Waivers.html

The drafting team received only one comment on the SAR, and this comment was based on a misunderstanding that the requester was proposing changes to VRFs and VSLs – the requester is not proposing any changes to VRFs or VSLs, thus the SAR will remain unchanged.

- Stakeholders agreed that the waivers should be removed from the standards since MISO is now operating as its own Balancing Authority and the conditions under which the waivers were approved are no longer applicable.
- Stakeholders did not identify any associated business practices for consideration. One stakeholder suggested that a new SAR be developed to address a concern with resource planning for the Midwest ISO. Registration assignments or market design suggestions are not intended to be addressed in this SAR.
- Stakeholders agreed with the proposed modifications to BAL-006-2 and INT-003-3.
- One commenter suggested that the SAR DT also consider the removal of the third waiver reflected in the INT-003 standard - MISO Energy Flow Information Waiver. The Waiver was originally requested / approved to implement a multi-Control Area Energy Market. Even though the MISO Energy Flow Information Waiver says that it should also apply in the event that Control Areas in the RTO are combined into fewer Control Areas or into one Control Area it seems inconceivable that one would need a multi-control area waiver for one consolidated control area. The Midwest ISO considered recommending the removal of the Energy Flow Information Waiver, but felt the waiver was still applicable. The intent of the Energy Flow Information Waiver is to allow generation to load transfers to be uploaded to the IDC in lieu of eTags. The Midwest ISO believes this information is needed in the IDC to properly account for impacts on internal and external flowgates.

The drafting team made no changes to any of the standards following this comment period, and is recommending that the Standards Committee move the SAR forward and move the standards forward to for a pre-ballot review and subsequent balloting of the standards.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Individual	Edward C. Stein	Self-Retired								X		
2.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
3.	Individual	Jeffrey V Hackman	Ameren Services	X									
4.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
5.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
6.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Al Adamson	New York State Reliability Council	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	5. Kurtis Chong		Independent Electricity System Operator	NPCC	2								
	6. Sylvain Clermont		Hydro-Quebec TransEnergie	NPCC	1								
	7. Manuel Couto		National Grid	NPCC	1								
	8. Chris de Graffenried		Consolidated Edison Co. of New York, Inc.	NPCC	1								
	9. Brian Evans-Mongeon		Utility Services	NPCC	8								
	10. Mike Garton		Dominion Resources Services, Inc.	NPCC	5								
	11. Brian Gooder		Ontario Power Generation Incorporated	NPCC	5								
	12. Kathleen Goodman		ISO - New England	NPCC	2								
	13. David Kiguel		Hydro One Networks Inc.	NPCC	1								
	14. Michael Lombardi		Northeast Lombardi	NPCC	1								
	15. Randy MacDonald		New Brunswick System Operator	NPCC	2								
	16. Bruce Metruck		New York Power Authority	NPCC	6								
	17. Robert Pellegrini		The United Illuminating Company	NPCC	1								
	18. Michael Schiavone		National Grid	NPCC	1								
	19. Chris Orzel		FPL Energy/NextEra Energy	NPCC	5								
	20. Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC	3								
	21. Gerry Dunbar		Northeast Power Coordinating Council	NPCC	10								
	22. Lee Pedowicz		Northeast Power Coordinating Council	NPCC	10								
7.	Individual	Alan Gale	City of Tallahassee					X					
8.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
9.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**	**Segment Selection**								
	1. Wes Hutchison		Transmission Operational Analysis & Support	WECC	1								
10.	Individual	Dan Rochester	Ontario IESO		X								

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Carol Gerou	NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	Wisconsin Public Service	MRO	1, 3, 5
2.	Terry Bilke	MISO	MRO	2
3.	Ken Goldmsith	Alliant Energy	MRO	4
4.	Jim Haigh	Western Area Power Administration	MRO	1, 6
5.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
6.	Joe Knight	Great River Energy	MRO	1, 3, 5, 6
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Scott Nickels	Rochester Public Utilties	MRO	3, 4, 5, 6
9.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
10.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6

12.	Group	Phil Riley	Public Service Commission of South Carolina									X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mignon L. Clyburn	Public Service Commission of South Carolina	SERC	9
2.	Elizabeth B. "Lib" Fleming	Public Service Commission of South Carolina	SERC	9
3.	G. O'Neal Hamilton	Public Service Commission of South Carolina	SERC	9
4.	John E. "Butch" Howard	Public Service Commission of South Carolina	SERC	9
5.	Randy Mitchell	Public Service Commission of South Carolina	SERC	9
6.	Swain E. Whitfield	Public Service Commission of South Carolina	SERC	9
7.	David A. Wright	Public Service Commission of South Carolina	SERC	9

13.	Group	Patrick Brown	PJM		X								
14.	Group	Jim Case	SERC OC Standards Review Group	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
	1. Tim Hattaway — PowerSouth Energy Cooperative — SERC — 1, 3, 5 2. Keith Steinmetz — EON-US — SERC — 1, 3, 5 3. John Troha — SERC Reliability Corporation — SERC — 10 4. Marc Butts — Southern Company — SERC — 1, 3											
15.	Individual — Jason Marshall	Midwest ISO		X								
16.	Individual — Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

1. **The SAR is limited to removing the identified MISO waivers from BAL-006-1 and INT-003-2. Do you agree that these waivers should be removed since MISO is now operating as its own Balancing Authority and the conditions under which the waivers were approved are no longer applicable? If not, please explain in the comment area.**

Summary Consideration: Stakeholders agreed that the waivers should be removed since MISO is now operating as its own Balancing Authority and the conditions under which the waivers were approved are no longer applicable.

Organization	Yes or No	Question 1 Comment
Ameren Services	No	While the stated purpose is "limited to removing MISO waivers", the redline for the the INT shows in the revision block that VRF and VSL will be modified. This looks like a back door revision under this SAR language.
Response: Thank you for your comment. A set of approved VRFs and VSLs exist for this standard. These VRF's and VSL's are in the documents contained here: **VRF's:** **http://www.nerc.com/docs/standards/rs/VRF_Standards_Applicability_Matrix_2009Feb3.xls** **VSL's:** **http://www.nerc.com/docs/standards/rs/VSL_Matrix_2009Feb10.doc** The VRF's and VSL's inserted into the INT standard are only the approved elements from these documents. It is the intention of NERC to insert these into revisions to standards so that the complete standard is available in a single document. There will be no revisions to either the VRF's or the VSL's under this project.		
Edward C. Stein	Yes	
Duke Energy	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
NIPSCO	Yes	
City of Tallahassee	Yes	
Manitoba Hydro	Yes	
Bonneville Power Administration	Yes	
Ontario IESO	Yes	
NERC Standards Review Subcommittee	Yes	
Public Service Commission of South Carolina	Yes	
PJM	Yes	
SERC OC Standards Review Group	Yes	
Midwest ISO	Yes	
FirstEnergy	Yes	

2. Are you aware of any associated business practices that we should consider with this SAR? If yes, please explain in the comment area.

Summary Consideration: Stakeholders did not identify any associated business practices for consideration. One stakeholder suggested that a new SAR be developed to address a concern with Resource Planning for the Midwest ISO. Registration assignments or market design suggestions are not intended to be addressed in this SAR.

Organization	Yes or No	Question 2 Comment
Edward C. Stein	Yes	This is more of a reliability practice than a business practice. It is my understanding that MISO has not accepted the reliability role of Resource Planner (RP), similar to PJM, even though they have accepted the role of Balancing Authority (BA) and run one of the largest electricity Markets in America. The only difference that I see is that MISO runs an energy only market where as PJM runs both an energy market and a capacity market. It very well may be that MISO is moving towards two markets, energy and capacity. My concern is that given the time that it took MISO to become a BA, it will take even longer for MISO to move towards two markets and the role of RP. I recommend that the Drafting Team develop a separate SAR to address the RP issue in order to speed the process of eliminating the MISO waivers since they truly are a BA.
Response: Thank you for your comment. Registration assignments or market design suggestions are not intended to be addressed in this SAR.		
City of Tallahassee	Yes	
Duke Energy	No	
Ameren Services	No	
American Electric Power	No	
NIPSCO	No	

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	No	
Bonneville Power Administration	No	
Ontario IESO	No	
NERC Standards Review Subcommittee	No	
Public Service Commission of South Carolina	No	
PJM	No	
SERC OC Standards Review Group	No	
Midwest ISO	No	
FirstEnergy	No	

3. Do you agree with the proposed modifications to BAL-006-2 and INT-003-3? If not, please explain in the comment area.

Summary Consideration: Stakeholders agreed with the proposed modifications to BAL-006-2 and INT-003-3.

Organization	Yes or No	Question 3 Comment
Ameren Services	No	See response to Q1
Response: Please see response to Question 1.		
Edward C. Stein	Yes	
Duke Energy	Yes	
American Electric Power	Yes	
NIPSCO	Yes	
City of Tallahassee	Yes	
Manitoba Hydro	Yes	
Bonneville Power Administration	Yes	
Ontario IESO	Yes	
NERC Standards Review Subcommittee	Yes	
Public Service Commission of	Yes	

Organization	Yes or No	Question 3 Comment
South Carolina		
PJM	Yes	
SERC OC Standards Review Group	Yes	
Midwest ISO	Yes	
FirstEnergy	Yes	

4. If you have any other comments on the SAR or proposed modifications to BAL-006-2 or INT-003-3 that you haven't provided in response to the previous questions, please provide them here.

Summary Consideration: One commenter suggested that the SAR DT also consider the removal of the third waiver reflected in the INT-003 standard - MISO Energy Flow Information Waiver. The Waiver was originally requested / approved to implement a Multi-Control Area Energy Market. Even though the MISO Energy Flow Information Waiver says that it should also apply in the event that Control Areas in the RTO are combined into fewer Control Areas or into one Control Area it seems inconceivable that one would need a multi-control area waiver for one consolidated control area. The Midwest ISO considered recommending the removal of the Energy Flow Information Waiver, but felt the waiver was still applicable. The intent of the Energy Flow Information Waiver is to allow generation to load transfers to be uploaded to the IDC in lieu of eTags. The Midwest ISO believes this information is needed in the IDC to properly account for impacts on internal and external flowgates.

Organization	Question 4 Comment
FirstEnergy	FirstEnergy agrees that the BAL-006 waiver is obsolete given the Amended BA Agreement and matrix whereby MISO alone calculates and records its own inadvertent interchange and verifies net interchange with its neighbors. Absent the Amended BA Agreement/Matrix, the waiver was needed to give MISO an inadvertent account for its market. The waiver also specified that control areas within MISO would operate to net scheduled interchange with MISO, which is no longer the case under the Amended BA Agreement/Matrix. FirstEnergy also supports the two identified waivers proposed for removal from the INT-003 standard as they are also unneeded since the Amended BA Agreement/Matrix assigns interchange scheduling solely to MISO. FirstEnergy ask that the SAR DT also consider the removal of the third waiver reflected in the INT-003 standard - MISO Energy Flow Information Waiver. The Waiver was originally requested/approved to implement a multi-Control Area Energy Market. Even though the MISO Energy Flow Information Waiver says that it should also apply in the event that Control Areas in the RTO are combined into fewer Control Areas or into one Control Area it seems inconceivable that one would need a multi-control area waiver for one consolidated control area. We ask that the SAR DT reconsider the need for the MISO Energy Flow Information Waiver and provide reason for its continued use if deemed appropriate.
Response: Thank you for your comment. The Midwest ISO considered recommending the removal of the Energy Flow Information Waiver, but felt the waiver was still applicable. The intent of the Energy Flow Information Waiver is to allow generation to load transfers to be uploaded to the IDC in lieu of eTags. The Midwest ISO believes this information is needed in the IDC to properly account for impacts on internal and external flowgates.	

Organization	Question 4 Comment
Northeast Power Coordinating Council	We don't have any comments at the present time.
NERC Standards Review Subcommittee	N/A

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement
Ballot Pool and Pre-ballot Window
July 27–August 27, 2009

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2009-18: Withdraw Three Midwest ISO Waivers
The following proposed standards have been have been posted for a 30-day pre-ballot review:

- BAL-006-2 — Inadvertent Interchange
- INT-003-3 — Interchange Transaction Implementation

The revisions are specifically for the removal of three Midwest ISO waivers from BAL-006-1 and INT-003-2. Registered Ballot Body members may join the ballot pool to be eligible to vote on the standards **until 8 a.m. EDT on August 27, 2009**. An implementation plan has been posted with the standards.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2009-18_MISO_Removal_in@nerc.com.

Next Steps
Voting will begin shortly after the pre-ballot review closes.

Project Background:
The proposed standards have been revised to remove three Midwest ISO waivers. The three waivers identified below were drafted to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. Now that the Midwest ISO is a Balancing Authority, these waivers are no longer needed by the Midwest ISO. Removing these waivers (or references to the Midwest ISO) will make the standards clearer.

- Inadvertent Accounting Waiver from BAL-006 — Inadvertent Accounting
- Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation
- Enhanced Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation

The scope of this project is limited to the removal of the three identified waivers — there are no conforming changes to the applicability, requirements, measures or compliance elements of the standard.

Applicability of Standards in Project:
Balancing Authorities

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Standard Authorization Request Form

Title of Proposed Standard	Withdraw 3 Midwest ISO Waivers
Request Date	April 2, 2009
SC Approval Date	April 15, 2009

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Terry Bilke	☐	New Standard
Primary Contact	Midwest ISO	☒	Revision to existing Standards INT-003-2 BAL-006-1
Telephone Fax	317-249-5463 317-249-5358	☐	Withdrawal of existing Standard
E-mail	tbilke@midwestiso.org	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

Three of the waivers in the current NERC Standards were drafted to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. Now that the Midwest ISO is a Balancing authority, these waivers are no longer needed by the Midwest ISO. Removing these waivers (or references to the Midwest ISO) will make the standards clearer.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

Remove unnecessary information from the standards and eliminate confusion.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

References to the Midwest ISO should be removed from the "Scheduling Agent Waiver" associated with INT-003-2 – Interchange Transaction Implementation.
The "Enhanced Scheduling Agent Waiver" associated with INT-003-2 should be retired.

References to the Midwest ISO should be removed from the "RTO Inadvertent Interchange Accounting Waiver" associated with BAL-006-1 – Inadvertent Interchange.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) See the "brief description".

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
INT-003-2	Waivers mentioned in this standard.
BAL-006-1	Waivers mentioned in this standard.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

A. Introduction

1. Title: **Inadvertent Interchange**

2. Number: BAL-006-2

3. Purpose:

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. Applicability:

4.1. Balancing Authorities.

5. Effective Date: First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R4.1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following

month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

E. Regional Differences

1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	To be determined.	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver	Revision

A. Introduction

1. Title: **Inadvertent Interchange**

2. Number: BAL-006-~~1~~2

3. Purpose:

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. Applicability:

4.1. Balancing Authorities.

5.

~~5.~~**Effective Date:** ~~May 1, 2006~~ First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

~~This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.~~

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R4.1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

E. Regional Differences

1. ~~MISO RTO~~ Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004~~. This regional difference will be extended to~~ includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	To be determined.	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver	Revision

A. Introduction

1. Title: **Interchange Transaction Implementation**

2. Number: INT-003-3

3. Purpose:

To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. Applicability

4.1. Balancing Authorities.

5. Effective Date: First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. (*Violation Risk Factor: Medium*)

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: (*Violation Risk Factor: Lower*)

R1.1.1. Interchange Schedule start and end time. (*Violation Risk Factor: Lower*)

R1.1.2. Energy profile. (*Violation Risk Factor: Lower*)

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. (*Violation Risk Factor: Medium*)

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule's start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority's ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Balancing Authority shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
R1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.2	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.2	The sending or receiving Balancing Authority experienced	The sending or receiving Balancing Authority experienced	The sending or receiving Balancing Authority experienced	The sending or receiving Balancing Authority experienced

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

E. Regional Differences

MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
3	To be determined.	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver	Revised

A. Introduction

1. Title: **Interchange Transaction Implementation**

2. Number: INT-003-~~2~~3

3. Purpose:

To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. Applicability

4.1. Balancing Authorities.

5. Effective Date: ~~January 1, 2007~~First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. (*Violation Risk Factor: Medium*)

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: (*Violation Risk Factor: Lower*)

R1.1.1. Interchange Schedule start and end time. (*Violation Risk Factor: Lower*)

R1.1.2. Energy profile. (*Violation Risk Factor: Lower*)

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. (*Violation Risk Factor: Medium*)

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule's start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority's ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Balancing Authority shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
R1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.1.2	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.2	The sending or receiving Balancing Authority experienced one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

E. Regional Differences

~~1.MISO Scheduling Agent Waiver dated November 21, 2002.~~

~~2.MISO Enhanced Scheduling Agent Waiver dated July 16, 2003.~~

~~3.~~MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
3	To be determined.	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver	Revised

Implementation Plan for Project 2009-18

This project involves the removal of MISO Waivers from the following two standards:

BAL-006-2 — Inadvertent Interchange

INT-003-3 — Interchange Transaction Implementation

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the revisions to these two standards can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no new or revised definitions and no proposed revisions to any other standards as part of this project.

Compliance with Standard

The requirements in BAL-006-2 and in INT-003-3 apply solely to entities registered to perform the Balancing Authority function.

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard. Because the proposed modification is the removal of a waiver that is no longer needed, the proposed effective date does not anticipate that the affected entities will need any time to prepare for the revision.

The revisions to the standards should become effective as early as practical, and the following dates have been proposed:

> The proposed revisions to both standards should become effective on the first day of the first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

MISO Waivers Proposed for Removal:

RTO Inadvertent Interchange Accounting

(Approved by the NERC Operating Committee March 23–25, 2004)

This waiver was carried over with the development of Version 0 standards into BAL-006.

Organization

The control area participants of the Midwest ISO

Operating Policy

Standards
Policy 1F, Inadvertent Interchange Standard

Requirements
Policy 1G 1.1. — Control Surveys (AIE Survey)
Policy 1G2.2. — Inadvertent Interchange Summaries (Surveys)

Explanation

NERC Policy 1.F "Inadvertent Interchange Standard" speaks only of control areas accounting for Inadvertent Interchange. The policy was written before the advent of RTOs.

The CONTROL AREA participants request that the RTO be given an Inadvertent Interchange account. This will support the RTO in meeting its FERC-directed market obligations.
The current model for an LMP market requires financial settlement of all energy receipts and deliveries. This means control areas operating within this market will pay for (or be paid for) their Inadvertent Interchange. Financial settlement of inadvertent is allowed under Policy 1.F. 5.2. (other payback methods) and the *Financial Inadvertent Settlement Waiver*.

The approved *Enhanced Scheduling Agent Waiver* authorizes the RTO to act as a sink or source Control Area in order to manage transactions into, out of, or through the RTO. Approval of this *Inadvertent Interchange Waiver* allows the RTO to manage any financially settled net imbalance with the Interconnection.

Continued Responsibilities

Control areas will continue to perform all the traditional Inadvertent Accounting tasks as outlined in NERC Policy 1.F. and Appendix 1.F. In other words, the RTO control areas will continue to:

- Verify daily Actual Net Interchange with their adjacent control areas and if there are differences, resolve them within the time frame in NERC Policy 1.F.
- Operate to "equal and opposite" Net Actual Interchange with their adjacent control areas.
- Operate to an "equal and opposite" Scheduled Net Interchange with the RTO, consistent with the current *Scheduling Agent Waiver*.
- Verify daily Scheduled Net Interchange with the RTO and if there are differences, resolve them within the time frame in NERC Policy 1.F.
- Report their monthly Inadvertent Interchange data to their respective Regions.

The RTO will also continue to perform all the Inadvertent Accounting tasks as an intermediate control area (as specified in the *Scheduling Agent Waiver*) and source or sink control area (as specified in the *Enhanced Scheduling Agent Waiver*) including:

- Verify daily Scheduled Net Interchange with the RTO control areas and adjacent control areas, and if there are differences, resolve them within the time frame in NERC Policy 1.F.

- Operate to an "equal and opposite" Scheduled Net Interchange with the RTO control areas and adjacent control areas.
- Operate so that the Scheduled Net Interchange of the RTO (Sum of the Scheduled Net Interchanges with the RTO control areas and adjacent control areas) is zero (or equal to the RTO Inadvertent Payback as outlined below).

New Responsibilities

Financially settled Inadvertent would be removed from the control areas' balances. The RTO inadvertent account would reflect the net RTO imbalance with the Interconnection. In order to accomplish this, the RTO would add "equal and opposite" schedules with the RTO control areas after the settlement. The net of these "settlement" schedules will be zero.

As requested by the NERC Resources Subcommittee, the RTO will report its Inadvertent Interchange balance to ECAR. RTO reporting will be consistent with the requirements and timelines for control areas outlined in Policy 1F. In addition, the RTO will maintain records of Inadvertent Interchange financially settled with each control area and will provide AIE data (pre and post settlement) for any surveys or formal data requests.

The RTO will manage and pay back its net Inadvertent Interchange balance following NERC policy. Inadvertent payback will be initiated based on an objective and publicly available process that is triggered on balances exceeding statistical norms (allows normal "breathing" of balances). Inadvertent Payback will be done during periods and in amounts such that payback will not burden others or interfere with time corrections. Financial gain will not factor into the decision to payback or recover Inadvertent Interchange.

Current Operating Reliability

This waiver request is to accommodate after-the-fact transfer of financially settled Inadvertent Interchange. The waiver has no impact on real-time balancing performed by the control areas. The RTO will always operate with a "net zero" Scheduled Interchange. The waiver will not affect the way the RTO control areas perform or calculate CPS and DCS.

The Control Area Participants believe this waiver promotes reliability for two reasons:

- It eliminates the incentive for burdening the Interconnection by manipulating imbalances for financial gain (taking in inadvertent during periods of high price and returning it when prices subside). This is consistent with NERC Operating Committee's charge to the Joint Inadvertent Interchange Task Force (JIITF) and moves the JIITF's recommendations closer to realization.
- Increased transparency as the influence of RTO's markets on the Interconnection will be apparent through this separate RTO Inadvertent Interchange account. Any scheduling or process errors would be traceable through this account.

Scheduling Agent Waiver

(Approved by the NERC Operating Committee on November 21, 2002)

This waiver was carried over with the development of Version 0 standards into INT-003.

Organization

The Control Area participants of:

- Alliance RTO
- Midwest ISO
- Southwest Power Pool
- Grid South

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs. The participants are requesting a Waiver of specific provisions of NERC Policy 1, "Generation Control and Performance," and Policy 3, "Interchange," to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of a SCHEDULING AGENT:

SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting. The following specific sections of NERC Policy 1 Version 1a, "Generation Control and Performance," and Policy 3, Version 4, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Standards

Policy 1

- Policy 1F, "Inadvertent Interchange Standard"

Requirements

Policy 1

- 1G 1.1 — Control Surveys (AIE Survey)

Policy 3

- 3A 4 — Interchange Transaction Implementation (Assessment)
- 3A 6 — Interchange Transaction Implementation (Implementation)
- 3B 4 — Interchange Schedule Implementation (Confirmation)

Explanation

The SCHEDULING AGENT would be the single point of contact for all external, non-participating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Intra-RTO TRANSACTIONS would be handled with the SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES. The RTO CONTROL AREA participants propose to:

1. Designate their RTO as a SCHEDULING AGENT to act on their behalf with all ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.
2. Include the SCHEDULING AGENT in the SCHEDULING PATH of all INTERCHANGE TRANSACTIONS effectively placing the RTO SCHEDULING AGENT in the role of an INTERMEDIARY CONTROL AREA with respect to INTERCHANGE TRANSACTION management.
3. Manage any "scheduling error" attributable to the SCHEDULING AGENT and internalize this scheduling error into the INADVERTENT INTERCHANGE accounts of the participating CONTROL AREAS.
4. Include the SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to an INTERMEDIARY CONTROL AREA. By establishing a SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:
    a. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will:
        i. Allow the participant RTO CONTROL AREAS to implement INTERCHANGE SCHEDULES directly with the SCHEDULING AGENT, significantly reducing the scheduling, coordination and checkout contacts of the participants.
        ii. Allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.
    b. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.
    c. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

Enhanced Scheduling Agent Waiver

(Approved by the NERC Operating Committee July 16–17, 2003)

This waiver was carried over with the development of Version 0 standards into INT-003.

Organization

The Control Area participants of:

- Midwest ISO

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs. The participants are requesting a Waiver of specific provisions of NERC Policy 3, "Interchange," to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of an ENHANCED SCHEDULING AGENT:

ENHANCED SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting.

The following specific sections of NERC Policy 3, Version 4, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Policy 3

- 3A 4 — Interchange Transaction Implementation (Assessment)
- 3A 6 — Interchange Transaction Implementation (Implementation)
- 3B 4 — Interchange Schedule Implementation (Confirmation)

Explanation

The ENHANCED SCHEDULING AGENT would be the single point of contact for all external, nonparticipating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Through TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. Into or Out Of TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the SINK or SOURCE CONTROL AREA, respectively. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES. The RTO CONTROL AREA participants propose to:

5. Designate their RTO as an ENHANCED SCHEDULING AGENT to act on their behalf with all external ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.
6. Include the Enhanced Scheduling Agent in the Scheduling Path of all Interchange Transactions in the role of Control Area (Intermediary, Source, or Sink as appropriate) with respect to Interchange Transaction management.
7. Include the ENHANCED SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to a CONTROL

AREA. By establishing an ENHANCED SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:

a. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the ENHANCED SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.

b. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.

c. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

d. The CONTROL AREAS within a RTO served by a ENHANCED SCHEDULING AGENT would be transparent to a transmission customer as the customer reserves transmission service and submits an energy schedule for pass-through transactions across said RTO.

e. By simplifying the transaction implementation process for both participant and non-participant CONTROL AREAS, automation of INTERCHANGE confirmation, scheduling and checkout with the ENHANCED SCHEDULING AGENT becomes achievable.

The proposal simplifies the transaction tagging process for market participants in that there is no longer a need to designate a specific CONTROL AREA contract path within or through the RTO where there may, in fact, be several parallel contract paths possible. The specific scheduling processes implemented between participating CONTROL AREAS within the RTO are internalized and transparent to the market, but will not violate any reliability criteria.

Current Operating Reliability Implications

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 3A4

The CONTROL AREA Assesses:

- Transaction start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- Scheduling Path (proper connectivity of ADJACENT CONTROL AREAS)

Conditions:

The Control Area Participants will allow the RTO Scheduling Agent to assess proper connectivity on the Scheduling Path.

Policy 3A6
Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

Conditions:
The applicants clarify that the Enhanced Scheduling Agent shall assume the role and responsibilities of the INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with regard to Policy 3, and the individual RTO's Control Areas do not appear in the Scheduling Path on the tag. The RTO's Control Areas will not incorporate these transactions into a schedule in their EMS.

Policy 3B4
INTERCHANGE SCHEDULE confirmation and implementation. The RECEIVING CONTROL AREA is responsible for initiating the CONFIRMATION and IMPLEMENTATION of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

INTERCHANGE SCHEDULE agreement. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:

- Interchange Schedule start and end time
- Ramp start time and rate
- Energy profile

Conditions:
The obligation with respect to confirmation and implementation of INTERCHANGE SCHEDULES under Policy 3B 4 shall be satisfied by the confirmation of all schedules with the Scheduling Agent. The Scheduling Agent shall assume the role and responsibilities that would otherwise be considered that of an INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with respect to all transactions and schedules involving the RTO or its Control Areas.

Additional Conditions

The Operating Committee approved this waiver on July 16, 2003 with the following condition:

> "With NERC and appropriate regional representation, audit and confirm the Midwest ISO's readiness to perform the functions detailed in the enhanced scheduling agent and energy flow information waivers before they go into effect."

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Standards Announcement

Initial Ballot Window Open

August 27–September 8, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2009-18: Withdraw Three Midwest ISO Waivers

An initial ballot window for the following proposed standards is now open **until 8 p.m. EDT on September 8, 2009**:

- BAL-006-2 — Inadvertent Interchange
- INT-003-3 — Interchange Transaction Implementation

The revisions are specifically for the removal of three Midwest ISO waivers from BAL-006-1 and INT-003-2. An implementation plan has been posted with the standards.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The proposed standards have been revised to remove three Midwest ISO waivers. The three waivers identified below were drafted to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. Now that the Midwest ISO is a Balancing Authority, these waivers are no longer needed by the Midwest ISO. Removing these waivers (or references to the Midwest ISO) will make the standards clearer.

- Inadvertent Accounting Waiver from BAL-006 — Inadvertent Accounting
- Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation
- Enhanced Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation

The scope of this project is limited to the removal of the three identified waivers — there are no conforming changes to the applicability, requirements, measures, or compliance elements of the standard.

Applicability of Standards in Project

Balancing Authorities

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Standards Announcement

Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2009-18: Withdraw Three Midwest ISO Waivers

The initial ballot for the following proposed standards ended September 8, 2009:

- BAL-006-2 — Inadvertent Interchange
- INT-003-3 — Interchange Transaction Implementation

Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 85.28%
Approval: 99.62%

The ballot pool approved the standards. Since there was no negative ballot that included a comment, these results are final. Ballot criteria details are listed at the end of the announcement.

Next Steps

The standards will be submitted to the NERC Board of Trustees for adoption.

Project Background

The proposed standards have been revised to remove three Midwest ISO waivers. The three waivers identified below were drafted to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. Now that the Midwest ISO is a Balancing Authority, these waivers are no longer needed by the Midwest ISO. Removing these waivers (or references to the Midwest ISO) will make the standards clearer.

- Inadvertent Accounting Waiver from BAL-006 — Inadvertent Accounting
- Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation
- Enhanced Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation

The scope of this project is limited to the removal of the three identified waivers — there are no conforming changes to the applicability, requirements, measures, or compliance elements of the standards.

Project page: http://www.nerc.com/filez/standards/Project2009-18_Withdraw_Three_MISO_Waivers.html

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Ballot Results

Ballot Name:	Project 2009-18 - Withdraw Three Midwest ISO Waivers _in
Ballot Period:	8/27/2009 - 9/8/2009
Ballot Type:	Initial
Total # Votes:	168
Total Ballot Pool:	197
Quorum:	**85.28 % The Quorum has been reached**
Weighted Segment Vote:	99.62 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	49	1	37	0.974	1	0.026	4	7
2 - Segment 2.	9	0.7	7	0.7	0	0	1	1
3 - Segment 3.	51	1	37	1	0	0	5	9
4 - Segment 4.	12	0.9	9	0.9	0	0	2	1
5 - Segment 5.	35	1	26	1	0	0	4	5
6 - Segment 6.	23	1	20	1	0	0	0	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.4	4	0.4	0	0	0	2
9 - Segment 9.	6	0.4	4	0.4	0	0	1	1
10 - Segment 10.	6	0.4	4	0.4	0	0	2	0
Totals	**197**	**6.8**	**148**	**6.774**	**1**	**0.026**	**19**	**29**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	Central Maine Power Company	Brian Conroy	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Albert Poire	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	JEA	Ted E. Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Kissimmee Utility Authority	Joe B Watson		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	National Grid	Manuel Couto		
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Mark Sampson		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana		
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	

3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	Edward W Pourciau	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Lakeland Electric	Mace Hunter		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Michael Lupo		
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters		
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	Mark Alberter	Abstain	
3	Salt River Project	John T. Underhill	Abstain	
3	San Diego Gas & Electric	Scott Peterson		
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Abstain	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power - Ohio	Kevin L Holt		
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Northern California Power Agency	Fred E. Young	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Consumers Energy	James B Lewis		
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Abstain	

5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp Energy	David Godfrey	Abstain	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik		
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Tampa Electric Co.	Joann Wehle		
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	Edward C Stein	Edward C Stein	Affirmative	
8	James A Maenner	James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G Dvorsky		
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Abstain	
10	Midwest Reliability Organization	Dan R Schoenecker	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Abstain	

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